Decision 09-08-026 August 20, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 08-03-008 (Filed March 13, 2008)

DECISION ADOPTING COST-BENEFIT METHODOLOGY FOR DISTRIBUTED GENERATION

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DECISION ADOPTING COST-BENEFIT METHODOLOGY FOR DISTRIBUTED GENERATION

1. Summary of Decision

This decision adopts a methodology for assessing the costs and benefits of distributed generation (DG). DG includes customer-owned generation facilities such as solar photovoltaics, wind turbines, biogas, fuel cells, microturbines, small gas turbines, internal combustion engines, and combined heat and power cogeneration plants.

The primary purpose of this inquiry into cost-benefit methodologies is to assure that the state's support for DG projects, such as those funded through the Commission's Self-Generation Incentive Program (SGIP)[1] and the California Solar Initiative (CSI), is evaluated in an economically sound manner. Both CSI and SGIP provide incentives up to 1 or 3 megawatts (MWs), respectively, depending on facility type, but eligible DG facilities can be sized up to 5 MW. Today's decision directs that the adopted methodology be used immediately to assess ratepayer supported DG programs, i.e., SGIP and CSI, which support projects as large as 5 MW. This will assure that state programs, which promote DG facilities as high-priority energy resources, are properly informed by a sound measure of those programs' costs and benefits. Given that many of the initiatives supporting DG in California are fundamentally market transformation programs, a robust cost-benefit analysis is critical in assessing progress toward the over-arching goal of reducing the cost of DG to the point where DG is

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[1] Effective January 1, 2008, Pub. Util. Code § 379.6 limits SGIP eligibility to wind and fuel cell technologies. The cost-benefit methodology adopted in this order will apply to all technologies that may have received incentives under SGIP prior to 2008, such as

Footnote continued on next page

competitive with incumbent technologies. A cost-benefit analysis is not the only measure of a policy or program's worth, but it is an essential input when deciding to continue, modify, or cancel a particular effort.

The methodology we adopt today is designed to reflect the costs and benefits of DG facilities from various perspectives and employs currently available data as inputs. These inputs can be modified in the future with the development of more precise economic values for some variables.

This decision adopts the following general policies and principles for cost-benefit methods used to analyze DG:

- DG projects and programs should be analyzed using three tests described in the Standard Practice Manual, namely, the Participant Test, the Total Resource Cost Test (including its variant, the Societal Test), and the Program Administrator Cost Test;

- The variables for each of the three adopted tests are summarized in Attachment A of this decision and include Commission-approved avoided costs, values included in utility tariffs and actual program data as reported by the program administrators;

- The DG cost-benefit tests should use the avoided cost methodology developed by Energy and Environmental Economics Inc. (E3) and adopted in Decision (D.) 05-04-024, and later updated in D.06-06-063. The inputs to this E3 avoided cost methodology should be consistent with those used in Commission directed evaluation of energy efficiency programs. Any modifications to adapt these avoided costs to DG facilities shall be thoroughly documented and justified by the entity performing the cost-benefit analysis;

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solar photovoltaics, microturbines, internal combustion engines, and combined heat and power plants.

- The "physical assurance" requirement that a DG facility will not ever require utility service over deferred utility investment, as set forth in D.03-02-068, should continue to apply to DG facilities that contract with a utility for transmission and distribution capacity deferrals. Nevertheless, the method used by Itron in its SGIP Year 6 Impact Report should be used to determine the collective transmission and distribution investment deferrals of all DG facilities;

- All relevant environmental benefits currently used in evaluation of energy efficiency programs should be included in the cost-benefit models, whether or not their impacts result from regulation or compliance with state or federal law;

- The cost-benefit analysis of DG programs, such as SGIP and CSI, should include a qualitative analysis of the market transformation effects of these DG programs; and

- Bill credits under net metering and energy exported to the grid by DG facilities should be included as costs and benefits of net metering in the cost-benefit tests, where appropriate.

We direct the Commission's Energy Division to oversee the application of this methodology by hiring an independent entity to perform a cost-benefit analysis for the SGIP and CSI programs using the methodology adopted in this decision. The work should be funded by the administrative budgets for SGIP and CSI, respectively. Further, we direct the utilities and SGIP and CSI program administrators to obtain, facilitate the obtainment of, or supply all program data, participant (or DG customer) data, or other relevant information requested by Energy Division, or its contractor, for this analysis. Energy Division should initiate work to retain a contractor for cost-benefit analysis within 30 days from the date of this order. The Energy Division should oversee this analysis work to ensure the appropriate application of the methodology described herein. Once the work is complete, the assigned Administrative Law Judge (ALJ) shall provide parties an opportunity to comment on the final report as part of the Commission's commitment to consider ongoing refinements to this methodology.

Since the time that we began this effort in 2004, DG has expanded and evolved. For example, our SGIP now provides incentives to advanced energy storage technologies that accompany DG facilities. The term DG is no longer limited to customer-owned facilities, as the facilities may be owned by a third party, and may refer to generation that is either on the "customer-side" of the meter, with occasional export to the grid, or generation that is on the utility, or "system-side" of the meter, with occasional customer use, but expressly designed to net export. System-side DG can also be thought of as wholesale DG. The methodology we adopt today may have applicability to these other forms of DG, which may be larger than 5 MW, and the Commission may, at a future date or in another proceeding, choose to explore application of this methodology to other forms of DG.

2. Procedural Background

As part of this rulemaking, which considers a number of policy and program issues related to DG resources in California, we stated our intention to adopt cost-benefit models. The scoping memo for Rulemaking (R.) 04-03-017 discusses our intent to use cost-benefit analyses to compare resource options as part of utility resource planning, to determine how to choose among candidate DG technologies and projects for incentives and other funding, to assess project alternatives as part of utility power procurement, and to assist in measuring and evaluating the effectiveness of DG incentive programs. There may be other uses for a rigorous cost-benefit test in the future.

We embarked on development of a cost-benefit methodology collaboratively with the California Energy Commission (CEC) by conducting a workshop on May 5, 2004. The workshop focused on identifying specific types of costs, benefits, and potential methodologies to quantify them. Parties filed comments in response to the workshop. The Commission conducted hearings in this proceeding on cost-benefit methodologies from May 11-13, 2005 before ALJ Kim Malcolm. The matter was submitted on July 12, 2005 with the receipt of reply briefs. A proposed decision was issued in September 2005 and comments on the proposed decision were filed that same month. The proposed decision was subsequently withdrawn from the Commission's agenda.

On March 2, 2006, the Commission opened a new rulemaking on DG and CSI, R.06-03-004. The prior DG rulemaking, R.04-03-017 was closed and its record was transferred to the new docket. The portion of R.06-03-004 regarding cost-benefit methodology issues was assigned to ALJ Dorothy Duda. On March 13, 2008, R.06-03-004 was closed and the record transferred to R.08-03-008, also assigned to ALJ Duda.

On February 3, 2009, ALJ Duda issued a ruling soliciting comments on preliminary revisions to the 2005 proposed decision and taking official notice of several reports and documents issued since the previous submittal date in July 2005. Parties provided comments in response to this ruling on February 25, 2009 and reply comments on March 9, 2009.

Active parties in this proceeding represented regulated energy utilities, namely Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company and Southern California Gas Company (SDG&E/SCG), the Commission's Division of Ratepayer Advocates (DRA), and DG developers, customers and their associations, including the California Clean DG Coalition (CCDC), the California Solar Energy Industries Association (CalSEIA), First Solar, FuelCell Energy Inc. (FCE), the Interstate Renewable Energy Council (IREC), the California Energy Storage Alliance (CESA), Cogeneration Association of California and the Energy Producers and Users Association (CAC/EPUC), PV Now and Americans for Solar Power (ASPv) (now known jointly as the Solar Alliance), and the City of San Diego. We refer to these non-utility parties collectively in some places as "DG Proponents." The California Center for Sustainable Energy (CCSE), which administers DG programs in the SDG&E territory, was also active in the proceeding in 2009.

3. Background on Issues and Policy

3.1. Overview of Cost-Benefit Approaches

Our inquiry with regard to a DG cost-benefit methodology evolves from our desire to promote as much DG as is sensible for California, armed with information about the costs and benefits of DG resources. DG differs somewhat from other generation resources in that it is small, can be located in or near the load center, and it may have fewer environmental impacts than more traditional energy resources. We have elaborated on the value of DG facilities to California utility customers and its economy in several Commission orders and the Energy Action Plan, issued by this Commission and the CEC. The full value of supporting investments in DG is not solely determined by performing a quantitative cost-benefit analysis, but such an analysis can be a useful tool in evaluating DG policies and programs.

This order proceeds to identify and specify the quantification of all relevant costs and benefits related to DG, which function as inputs to a cost-benefit methodology. The methodology may then be used to analyze the wisdom of ratepayer funding for DG projects, the allocation of project development costs between project developers and ratepayers, the benefits of DG relative to other energy resources available to jurisdictional utilities, and the progress that the state's market transformation programs have made in making DG competitive with central station energy resources.

The parties to this proceeding identified a variety of possible costs and benefits associated with DG, either in workshops or during the hearings. Parties identified the following potential costs of DG projects:

- Costs to integrate the DG project with the utility's distribution system;
  Utility revenue loss due to displaced usage of transmission and distribution facilities;
- Utility/Department of Water Resources (DWR) revenue loss due to avoided commodity purchase—energy, capacity, bonds;
- DG project costs—investment, maintenance, fuel, metering;
- Reduced stability and power quality;
- Costs of Ancillary services/VAR support,[2]
- Utility loss of revenue due to displaced thermal load, reduced sales of natural gas, and cost of ratepayer incentives for combined heat and power (CHP) generators;

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[2] Ancillary services/volt-ampere reactive power (VAR) support refers to services that ensure reliability and support the transmission of electricity from generation sites to customer locations. Such services may include: load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.

- Costs of mitigating air and water pollutants, and noise abatement;
- Utility DG program-related administrative costs;
- Cost of tax and other incentives; and
- Net metering costs.

Among the potential benefits of DG identified by the parties are:

- Reduced transmission and distribution line losses;
- Avoided purchases of other energy and resource adequacy capacity;
- Enhanced reliability;
- Improved stability and power quality;
- Provision of Ancillary Services/VAR support;
- Environmental benefits compared to central station facilities, including reduced air and water pollutants, promotion of environmental equity compared to large central station power plants;
- Thermal load provided in CHP applications;
- Increased responsiveness to load growth resulting from DG's modularity and scale;
- Lower market prices for power;
- Increased employment and tax revenue in California;

- National security benefits associated with reduced security risk to grid;
- Conservation of natural gas (i.e., reduced utility and/or end-user purchases of natural gas);
- Avoided utility capital costs (such as deferral of investment in transmission and distribution facilities);
- Avoided utility administrative, maintenance, insurance, and installation costs;
- Net Metering benefits; and
- Market transformation impacts (such as greater acceptance and increased demand for DG facilities and reduced system costs, both material and installation).

In this decision, we do not discuss each and every one of the potential costs and benefits that parties initially raised. Rather, we provide this list as background to show the starting point for our work. The actual DG costs and benefits that we incorporate into our methodology are discussed in Section 5 of this order and delineated in detail in Attachment A of this decision.

Of the costs and benefits identified in this proceeding, some will be relatively straightforward to quantify, while others will be more challenging to quantify, such as market transformation impacts. DG costs and benefits vary based on technology, fuel variable, application, size, location, and frequency and duration of the facility's use. Significantly, the value of DG depends on whether the calculation is from the perspective of the DG project owner, the utility or program administrator, or society overall. In D.03-02-068, the Commission found that DG can serve different purposes, such as onsite generation or as a distribution system alternative. The value of a DG project may depend on how the power is used, technology, fuel, and application. For this reason, this order evaluates a variety of methodologies that reflect various perspectives and types of DG.

Creating a cost-benefit methodology for DG programs is a technically complex exercise but is not a novel one. For many years, the Commission has used cost-benefit tests for energy efficiency programs. The Commission has used avoided costs both for analyzing energy efficiency cost-effectiveness and for assessing the value of and setting prices for "qualifying facilities," which are privately-owned energy resources that sell power to the utilities under the Public Utilities Regulatory Policies Act of 1981. Calculation of avoided costs in the context of energy efficiency has taken on even greater importance as these costs serve as the basis for incentive payments the utilities can earn under the Risk Reward Incentive Mechanism adopted by the Commission in D.07-09-043.

In this proceeding, our primary objective is to specify a methodology that reflects the appropriate costs and benefits of DG. A secondary but essential objective here is to determine the type of data or information to use to establish values for each of the variables used in the methodology.

The parties have used some existing studies and references in advocating for cost-effectiveness model types and specifications. The Commission has developed and used a cost-benefit model for existing energy efficiency program proposals in the "Standard Practice Manual" (SPM) used to guide energy efficiency program administration. The SPM presents a cost-benefit model using four tests. The SPM model was intended to be used for resource assessments generally but has so far been used primarily to evaluate energy efficiency programs. Although the SPM describes four cost-benefit tests, the Commission focuses on two of the tests, the Total Resource Cost Test and the Program

Administrator Cost Test, when evaluating utility energy efficiency programs. (*See* D.05-04-051, Ordering Paragraph 5, at 91.)

Also providing a foundation for the debate in this proceeding were two reports sponsored by the CEC and the Commission. One, issued by Itron in March 2005, is titled "Framework for Assessing the Cost-Effectiveness of the Self Generation Incentive Program" (Itron Framework).[3] The other, issued on October 25, 2004, by Energy and Environmental Economics, Inc. (E3), is titled "Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs" (E3 Report) and was submitted to the Energy Division and examined in R.04-04-025, the Commission's inquiry into energy avoided costs.

The Itron Framework uses the SPM cost-benefit methodology as a starting point, and specifies the model inputs that are relevant for DG projects. The E3 Report presents various avoided cost estimates, which were adopted by the Commission in D.05-04-024, and updated in D.06-06-063.[4] Avoided costs are inputs to cost-benefit models. For example, we could specify a cost-benefit model that measures avoided generation costs and avoided transmission line losses. An avoided cost in this context generally refers to a type of cost the utility avoids when the DG facility serves load the utility would otherwise have to serve. The generic avoided cost calculation may accurately reflect a DG facility's value to the system or it may serve as a baseline to which we might include

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[3] During hearings in May 2005, the Itron Framework was accepted into the evidence of this proceeding as Exhibit 37.

[4] In D.06-06-063, the Commission refined the interim avoided costs adopted in D.05-04-024 for specific energy efficiency resources and updated the natural gas and generation avoided costs to reflect more recent market realities for natural gas prices.

"adders" in the cost-benefit model to reflect an additional benefit (or cost) that is specific to a DG facility or DG facilities generally compared to other energy resources. For example, we may find that in addition to avoided transmission costs that are common to all resources that reduce load, we may include an adder in the cost-benefit calculation that recognizes the deferral of investment in a transmission line to serve a specific large customer with a DG facility.

Several additional reports provide additional views on a cost-benefit methodology for assessing DG resources and programs. In February 2007, Itron released a report titled "Solar PV Costs and Incentive Factors" (Itron Solar Cost Report). Itron has also released several reports evaluating the performance of SGIP, including the "CPUC SGIP Preliminary Cost-Effectiveness Evaluation Report" (Itron SGIP Evaluation) in September 2005, the "CPUC SGIP Fifth Year Impact Evaluation" (SGIP Year 5 Impacts) in March 2007, and the "CPUC SGIP Sixth Year Impact Evaluation" (SGIP Year 6 Impacts) in August 2007. Each of these reports contributes to the determination of accurate inputs into the methodology described in this document.

Finally, in November 2008, the CEC released a report entitled "Cost-Benefit Analysis of the Self-Generation Incentive Program," prepared by the CEC's consultant TIAX LLC. The report, which we refer to as the TIAX Report, was prepared pursuant to Section 379.6(f),[5] which required the CEC, in consultation with the CPUC and the California Air Resources Board, to evaluate the costs and benefits of ratepayer subsidies for renewable and fossil fuel

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[5] Section 379.6 was added to the Public Utilities Code by Assembly Bill 2778 (Lieber), Ch. 617, Stats of 2006. Except as otherwise noted, all statutory references are to the Public Utilities Code.

ultraclean and low-emission distributed generation. The TIAX Report categorized SGIP impacts in three categories, namely environmental, macroeconomic, and grid impacts. The TIAX Report is consistent with the core elements of the SPM, but is not bound by the SPM. The TIAX Report acknowledges that there are costs and benefits that have not been included in its analysis, and it further states that the Report "is intended to contribute to the ongoing debate related to the costs and benefits of DG, rather than settle it." (TIAX Report, at 74.) One notable difference between the TIAX Report's analysis and the methodology discussed in this decision is the TIAX Report's focus on macroeconomic effects, such as job gains and losses and tax revenues. The TIAX Report provides additional insight into cost-benefit approaches for analyzing DG and, in our view, its analysis is not inconsistent with the methodology we adopt in this decision.

3.2. Development of Avoided Costs in R.04-04-025

The Commission considered avoided costs in a separate docket, R.04-04-025, which is now closed. R.04-04-025 was initiated to establish avoided costs for the purpose of payments to Qualifying Facilities (QFs) and to develop a common methodology, consistent input assumptions, and consistent updating procedures for avoided costs across various Commission proceedings, with the goal of establishing "apples to apples" comparisons across resource options, to the greatest extent possible. (*See* R.04-04-025, issued April 22, 2004, at 2.) The various resource options we refer to include energy efficiency programs, demand response programs, utility resource planning and procurement, energy supply contracts with QFs, and DG programs. Significant decisions in R.04-04-025 include D.05-04-024, wherein the Commission adopted an avoided cost methodology for the purpose of evaluating the utilities' energy efficiency programs and D.06-06-063, wherein the Commission refined the interim avoided costs adopted in D.05-04-024. Also, in D.07-09-040, the Commission adopted a Market Index Formula to determine payments to QFs.

As the scoping memo issued in R.04-03-017 explains, the avoided costs developed in R.04-04-025 may be useful as elements of the cost-benefit models we adopt in this proceeding. Our intent here has been to identify the types of elements appropriate for a cost-benefit model to assess DG projects, which would include an avoided cost and may include other elements. To the extent a DG project avoids capacity, that avoided cost would be included in the DG cost-benefit model. The variables for that cost-benefit model, however, would not necessarily be limited to the avoided cost developed in R.04-04-025, without any consideration of specific DG avoided costs. The DG project may also provide additional benefits to ratepayers or society, or impose additional costs, relative to those that are incorporated in the avoided cost.

While the overall purpose of our effort in R.04-04-025 was to promote consistency in our application of avoided costs across programs and evaluation exercises, we do not pursue consistency in a vacuum. Where it is sensible to distinguish one type of facility or program from another because of costs or benefits associated with the facility or program, we intend to tailor our analysis. In this proceeding, we tailor the cost-benefit models in ways that reflect the unique circumstances of DG facilities, and do so without unreasonable delay.

For purposes of our DG cost-benefit methodology, we direct that the DG cost-benefit tests use the avoided cost methodology (also referred to herein as the

E3 Calculator)[6] adopted in D.05-04-024, and later modified by D.06-06-063. The E3 calculator adopted in D.05-04-024 is named after Energy and Environmental Economics (E3), the consultants that developed it. In D.05-04-024, the Commission specified the use of the E3 calculator for evaluation of energy efficiency programs, but also described the relevance of the calculator to other resources like DG. (See D.05-04-024, p. 12.) In D.06-06-063, the Commission set forth specific updates to the E3 Calculator. (See D.06-06-063, Ordering Paragraphs 16 and 17.) Further rulings and decisions in the Commission's energy efficiency proceedings continually refine the inputs used in the E3 Calculator to evaluate energy efficiency programs. We direct the use of the E3 Calculator for our DG cost-benefit tests, and we further specify that the inputs for avoided costs used in this methodology should be the same as those inputs currently in use for evaluating energy efficiency programs, except in limited exceptions as discussed below.[7] In other words, the avoided costs used to evaluate energy efficiency programs and DG should be the same, with few

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[6] The E3 calculator is a costing methodology implemented using a spreadsheet model and publicly available data, resulting in avoided cost estimates that are transparent and can easily be updated to reflect changes in major cost drivers, including the price of natural gas and the cost of new generation. D.06-06-063 refined the original E3 calculator by adopting time-of-use (TOU)-averaging correction factors and updating natural gas and electric generation avoided costs. The E3 Calculator, or avoided cost methodology, should not be confused with the E3 Calculator Tool, which is a spreadsheet that takes the avoided cost outputs of the E3 Calculator and calculates SPM cost-benefit test results using those avoided costs.

[7] The Commission's current requirements were set forth in "Assigned Commissioner's and Administrative Law Judge's Ruling Regarding May 15, 2008 Energy Efficiency Portfolio Plans for 2009-2011," R.06-04-010, April 21, 2008. The ruling requires updated 2007 generation cost values (2007 Market Price Referent) as adopted in Resolution E-4118 (October 4, 2007).

exceptions. Modifications to the E3 avoided cost data inputs must be documented and publicly vetted, as discussed below.

These avoided costs shall form the framework for our cost-benefit analysis, but we do not preclude the possibility of future modifications to these avoided costs to tailor them to DG facilities. The contractor chosen to perform our DG cost-benefit analysis shall provide thorough documentation of and justification for any modifications to the avoided costs currently used for evaluation of energy efficiency programs to adapt them to DG facilities. After the cost-benefit analysis has been performed, the ALJ will solicit comments on the completed analysis. If the contractor has suggested avoided cost modifications, the ALJ will solicit comments on those modifications and may hold workshops or hearings as deemed necessary on any avoided cost modifications.

3.3. Defining DG for Purposes of Modeling Costs and Benefits

As we stated in the opening of this order, DG facilities have evolved over the time period we have taken to establish a cost-benefit methodology. DG facilities vary significantly with regard to technologies, applications, size, and ownership. However, they all serve load in close proximity to the generation. When this proceeding began, the focus of our methodology was to evaluate customer-owned DG serving load on the customer-side of the meter. Generally, this meant facilities interconnected at distribution level voltages, and sized under 20 MW. At the present time, we recognize that DG may not always be customer-owned, as it could be owned by a third party, and it may be located on the utility, or system-side of the meter, expressly designed as a net exporter of power to the grid.

In the early course of this proceeding, one party, namely, CAC/EPUC suggested the Commission adopt the following standard definition for DG:

> "DG is generation located on a customer's site that produces electricity to serve some portion of the customer's load, or nearby load, or both."

CAC/EPUC suggested that this definition includes CHP facilities, also called cogeneration plants. CAC/EPUC argued that cogeneration is reliable, efficient, and environmentally beneficial. CAC/EPUC objected to any definition of DG that was limited to facilities that are connected to the utility's distribution system, arguing that such a definition inappropriately imposes size limits on projects that may be identified as DG (because some large cogeneration plants are connected to the grid at the transmission level). Generally, CAC/EPUC believed there should be no requirement that a project be connected to the utility grid. CCDC agrees with these comments.

We will not adopt the definition of DG proposed by CAC/EPUC for several reasons. First, it appears that one of CAC/EPUC's goals was to have CHP generation facilities interconnected at the transmission level considered DG. The proposed definition could create confusion about what facilities qualify for our various DG programs. We will not consider facilities interconnected at the transmission level as DG. Second, by adopting a cost-benefit methodology, we are not changing program parameters or creating new incentives. To qualify for incentives under SGIP, a DG facility must meet the eligibility requirements set forth in Pub. Util. Code § 379.6 and Commission decisions implementing that code section. To qualify for incentives under CSI, a DG facility must meet the definition of a "solar energy system" set forth in Section 2852 and Section 25781 of the Public Resources Code.[8] We see no reason to adopt a new definition here for cost-benefit analysis purposes, and potentially create confusion. Finally, we do not want to create a standard definition when the technologies, sizes, and uses of DG continue to evolve. Rather, we want to be able to apply our cost-benefit methodology to DG in its various forms, as they arise.

3.4. Assigning Specific Values to Adopted Variables

In addition to determining the types of models we should use to analyze DG projects, we specify the variables for each and identify data that should be used to calculate actual costs and benefits. This latter exercise is likely to be a moving target since many of the values for each cost-benefit model may change. These values may be derived from various information resources depending on the cost or benefit in question. For example, estimates of utility incentives are available in program guidelines and a total would be estimated according to DG facility energy production forecasts or metered data. Some model variables would use avoided costs as adopted in D.05-04-024 (as modified by D.06-06-063), or subsequent orders or rulings directing input updates for energy efficiency evaluation purposes.

The parties differ to some extent with regard to whether the Commission has the appropriate data to calculate costs and benefits immediately. ASPv would defer the adoption of final values, stating that third parties do not have ready access to much of the data needed for the models. It suggests conducting further proceedings to develop values for each variable. SCE also would await

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[8] See Attachment B for the relevant language of these code sections.

the final avoided costs adopted for DG in R.04-04-025. However, in the time period since SCE made that comment, R.04-04-025 closed without considering DG specifically. Other parties propose using what is available today, subject to future adjustments.

Several events have occurred since parties first made these comments in 2004 and 2005. The Commission updated avoided costs in D.05-04-024 and D.06-06-063 and the Commission has directed input adjustments to its avoided cost methodology for energy efficiency evaluation purposes as discussed previously in Section 3.2. Moreover, we have the benefit of additional SGIP evaluation reports prepared by Itron. We see no reason to further delay adoption of a cost-benefit methodology and we believe we have adequate data to analyze DG programs immediately. We also state our intent to modify inputs where existing information, data or estimates may be improved upon.

In order to avoid further delay in developing reasonable cost-benefit models, we herein either assign values to each variable or indicate the data source for the input, which may be historical program or utility information or more current, actual program data. In some cases, we describe a methodology for obtaining the needed value or input, such as avoided costs currently used for energy efficiency evaluation. Where relevant, we use existing tariffs, incentives and tax rates. The input variables and their data sources are summarized in Attachment A. We will modify these values as additional information becomes available or underlying values change. Specifically, we will allow parties an opportunity to comment on the final cost-benefit analysis, once it is completed. At that time, we will accept suggestions for refinements or alterations to the variables and data sources used in the analysis. The ALJ and/or Assigned

Commissioner may then hold further workshops or hearings as deemed necessary.

We find that the E3 avoided costs methodology adopted in D.05-04-024 and modified in D.06-06-063 should form the framework for our analysis, as long as it uses the most current inputs in use for energy efficiency evaluation purposes. The contractor performing the cost-benefit calculations may suggest modifications to these avoided costs to adapt them to DG facilities, as long as the modifications are thoroughly documented and justified in the accompanying report.

4. Developing Cost-Benefit Models According to Perspective

The costs and benefits of any energy project may vary significantly depending on whose perspective a model reflects. For example, a model that reflects ratepayer or utility concerns will focus primarily on the cost of a project relative to other energy resource options available for purchase by the utility. A model that reflects societal concerns will likely incorporate environmental impacts and equity concerns. A model that reflects the concerns of the DG owner will emphasize project profitability and payback period. The Standard Practices Manual presents four perspectives comparable to these and identifies them as follows:

(1) **The Participant Test** is the measure of the quantifiable costs and benefits to the customer participating in a program. An example of a benefit is the incentive paid by the utility under the program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

(2) **The Ratepayer Impact Measure (RIM) Test** (previously the Non-Participant Test) measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

(3) **The Total Resource Cost (TRC) Test** (and its variation, the Societal Test) measures the net costs of the program as a resource option based on the total costs of the program, including both the participants and the utility's costs. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g., environmental concerns, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

(4) **The Program Administrator (PA) Cost Test** measures the net costs of a program as a resource option based on the costs incurred by the PA (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC test, but costs are defined more narrowly.

Applying all four models would measure how costs and benefits are distributed among various groups or individuals.

The parties generally do not dispute the purpose of each of these models. They do, however, dispute their relative importance, how they should be applied and what the tests should measure. Each is discussed below.

4.1. Participant Test

The Participant Test measures the economic viability of a DG facility to the developer or customer installing the facility. While those who install DG will naturally have their own calculation of whether an investment is worthwhile, the Commission might want to conduct its own Participant Test to determine the level of incentive needed to promote investment and to help prevent the provision of incentive payments to "free riders."[9] As PG&E observes, it also appears that Section 2827(n) requires the Commission to complete a report on the costs and benefits of net metering from the perspective of "customer-generators." The Itron Framework identifies as benefits the customer's reduction in electricity bills, the value of displaced fuel with the use of waste heat, tax credits and other government incentives. Costs in this test include system costs, interconnection and emission control costs, and operations and maintenance expenses.

[9] "Free riders" are beneficiaries of a subsidy designed to motivate certain actions who would have taken that action without the subsidy.

No party opposed the use of a Participant Test and we state our intent to adopt a participant cost-benefit model here and to use it to evaluate the efficacy of and need for incentives at various levels. In subsequent sections, we discuss the variables for that test that were a source of controversy in this proceeding. Attachment A lists all of the variables for the test and the source of data for each variable.

4.2. The Ratepayer Impact Measure (RIM) Test

The RIM Test measures the relative costs and benefits of a DG project or program from the standpoint of utility ratepayers. The main difference between this test and the Total Resource Cost test discussed below is that the RIM Test measures potential transfers of wealth between ratepayers and DG facilities. Thus, it measures economic benefits as well as the allocation of costs between DG developers and utility ratepayers.

The utilities advocate for the application of the RIM Test in order to evaluate the financial impact of DG projects on utility customers from incentive payments and the loss of revenue from exemptions to standby charges and nonbypassable charges. SCE observes that the RIM Test is the only test that quantifies the allocation of costs and benefits between customers who install DG and those who do not. SCE observes that this test would measure the cost to ratepayers of such subsidies as exemptions from standby charges and nonbypassable charges, reduced transmission and distribution costs, and DG incentives paid through SGIP or CSI. SCE also states this information is necessary in order for the Commission to comply with Section 353.9, which requires that net costs associated with tariff modifications provided to DG customers be recovered only from the class or classes of customers eligible to receive the tariff modification.[10]

Some DG proponents oppose the use of such a test, viewing it as too narrow to capture the total benefits of DG projects. CCDC does not believe a RIM Test is necessary to evaluate DG, arguing that the Commission need only apply a modified version of the Societal Test already in use for energy efficiency projects and programs. CCDC cites prior Commission orders that have found the RIM Test inappropriate as a primary test of cost-effectiveness because it only looks at a portion of total costs, its results are affected by rate-design elements, and it does not identify least-cost resource options from an economic efficiency perspective.[11]

Ratepayer funds support DG programs as part of our policy to promote the development of a more diverse and environmentally sound energy network in California. Among the DG efforts they support through distribution rates are

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[10] The language of Section 353.9 is as follows: "In establishing the rates required under this article, the commission shall create a firewall that segregates distribution cost recovery so that any net costs, taking into account the actual costs and benefits of distributed energy resources, proportional to each customer class, as determined by the commission, resulting from the tariff modifications granted to members of each customer class may be recovered only from that class." The original proposed decision (mailed for comment in September 2005) referred to Section 353.9 and stated the Commission could employ a cost-benefit methodology to ensure compliance with this statute. The Commission addressed the DG rates referred to in this code section in D.01-07-027 and D.03-04-060, and in Resolutions E-3777, E-3778, and E-3779. We are satisfied that any obligation under Section 353.9 has been handled by those decisions and resolutions. We do not anticipate changes to these DG rates based on this cost-benefit methodology. Any review of DG rates or tariffs, or changes thereto, will not be considered in this rulemaking but are more appropriately considered in the proceeding wherein those rates or tariffs were adopted.

[11] See CCDC Comments, 2/25/09, at 6, citing D.92-02-075, at 22-24.

discounted rates, net metering, exemptions from standby charges and the cost responsibility surcharge (CRS), and direct financial incentives offered by the SGIP and CSI. The RIM test is intended to measure whether ratepayers as a group realize a net benefit from incentives paid for DG development. Despite this fact, we note that the Commission does not currently require the RIM Test to be performed and does not rely on it in the context of cost-effectiveness evaluation of utility energy efficiency programs. Rather, the Commission uses the Total Resource Cost Test and the Program Administrator Cost Test, as discussed in D.05-04-051 and described in further detail below, when evaluating energy efficiency programs.[12] Therefore, we will not require that the RIM Test be performed as part of our DG cost-effectiveness evaluation efforts. Nevertheless, we will leave discussion of the RIM Test in this order in the event the utilities wish to perform the test for rate design purposes relating to Section 353.9. In subsequent sections of this order, we discuss the variables that the RIM Test should include in the event it is used for that purpose. Where modifications to the Itron Framework approach are not explicitly addressed and adopted, the specifications in the Itron approach are implicitly adopted.

4.3. Total Resource Cost (TRC) Test and Societal Test

The TRC Test measures the relative costs and benefits of a DG project or program to both participants and non-participants, i.e., to society at large. A variant of the TRC test is the Societal Test. The purpose of both the TRC Test and the Societal Test is to determine the net benefits accruing to the subject economy or group.

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12 *See* D.05-04-051, Ordering Paragraph 5.

The Itron Framework proposes using the Societal Test for DG cost-benefit analysis because the test's perspective is comprehensive, considers externalities which affect society as a whole, and uses a lower discount rate than used in the TRC test. The Societal Test also ignores certain tax credits which are benefits to participants, but costs to other taxpayers in the relevant area considered by the test, thereby offsetting each other. When the relevant area for program evaluation is statewide, as is the case for CSI and SGIP, the tax treatment for the TRC Test and Societal Test should be the same. That is, state tax incentives would be considered a transfer and would not be measured by the tests, while Federal incentives would be measured as a benefit.

In commenting on the Itron Framework, most parties supported using the Societal Test, although some parties suggested modifications to Itron's specific interpretation of the test or the inputs Itron used. The DG Proponents suggest the Commission use the Societal Test as the primary test of DG cost-effectiveness. SCE supports use of the Societal Test as proposed in the Itron framework, commenting that the Societal Test is "flexible enough to allow inclusion of any quantifiable cost or benefit the Commission deems necessary to include in a DG cost-benefit analysis." (SCE reply brief, at 7.)

CCDC and ASPv both support use of the Societal Test, but they propose their own modifications to the tests. CCDC proposes modifications relating primarily to air emissions to correct what it believes are underestimates of electric emissions avoided costs and to tailor DG emissions avoided costs by DG technology, time period, and location. ASPv proposes its own cost-benefit methodology, which it calls the PLEASE matrix. According to ASPv, the PLEASE matrix has its roots in the SPM but is expanded to account for the unique benefits represented by DG. ASPv contends the Itron Framework fails to include a number of DG benefits because they are considered too general or too difficult to quantify. In light of the state's support for renewable DG, ASPv explicitly advocates for erring on the side of including too many benefits rather than too few even if some of those benefits are quantified at zero for now. PG&E and SCE both oppose ASPv's PLEASE matrix, alleging it is fundamentally flawed because its elements are highly speculative and unquantifiable.

PG&E suggests the Commission use the TRC test which is used to evaluate energy efficiency programs. City of San Diego also recommends the Commission evaluate the benefits of DG consistently with energy efficiency. DRA points out that the when the Commission evaluates its energy efficiency programs, it uses a hybrid test which more closely resembles the TRC test. (DRA Comments, 2/25/09, at 20.) Moreover, the Commission has declined to use the Societal Test to evaluate energy efficiency due to its lower discount rate and treatment of certain costs as transfers. (D.05-04-051, at 82.) DRA suggests the Commission use either the TRC test or both tests.

The purpose of our inquiry here is to develop a model for DG programs and facilities that best reflects the value of DG to society and ratepayers. To achieve this goal, we will use both the TRC and the Societal variant to asses costs and benefits of DG to both participants and non-participants, i.e., to Californians at large. While the Itron Framework suggested use of only the Societal Test, we see value in performing both tests, as suggested by DRA, because each test provides a unique perspective given different accounting for federal and state tax incentives and varying discount rates. In addition, we agree with the parties that have suggested our analysis of DG should mirror the cost-effectiveness analysis we currently perform for energy efficiency programs, which uses the TRC Test.

We decline to adopt the DG Proponents recommendation to make the TRC and/or the Societal Test the primary test because we prefer to assess DG from various perspectives, and not purely a societal one. However, we will include both the TRC and the Societal Test in our cost-benefit methodology.

We find the Societal Test, as presented in the Itron Framework, and the TRC Test as described in the SPM will each provide a useful perspective in assessing the costs and benefits of DG projects and programs. We consider both tests flexible enough to incorporate the inputs that we discuss in the remainder of this order. We prefer these tests to the PLEASE matrix proposed by ASPv because we favor using the tests already described in the SPM to adopting new and unique tests for DG.

Subsequent sections of this order address each variable that presented controversy between the parties. For example, the air emissions modifications suggested by CCDC are discussed in the section on environmental values. Attachment A lists all of the variables we adopt for each model and the data source for each. While the variables may not measure costs and benefits perfectly, they are reasonable for our purposes and may be modified as better information becomes available.

4.4. Program Administrator (PA) Cost Test

The PA Cost Test measures the net costs incurred by the PA for programs such as SGIP or CSI, including incentive costs, but excluding any net costs incurred by the program participants. In this test, revenue shifts are viewed as transfer payments between participants and all ratepayers.

The benefits measured by the PA Cost Test include avoided energy supply costs, and the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction (e.g., when a DG facility is producing energy). The costs measured by the PA Cost Test include the program costs incurred by the PA, the incentives paid to the customers, and increased supply costs for any periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout costs.

PG&E objects to use of the PA Cost Test as duplicative of the RIM Test. FCE maintains the PA Cost Test is confusing and could be replaced with a simple metric such as program administration costs per kilowatt (kW) of DG energy produced. SCE and DRA support use of the PA Cost Test, favoring a multi-perspective approach to our DG cost-benefit analysis. We conclude this test may be useful as a tool to evaluate program budgets and expenditures. We have already discussed in Section 4.2 above how this test is an important element in the Commission's evaluation of energy efficiency programs and how we prefer for our DG cost-benefit analysis to largely mirror energy efficiency evaluation. We will include the PA test in our cost-benefit methodology to be consistent with our use of the test for evaluation of energy efficiency programs.

5. Variables of Cost-Benefit Models

The SPM lists each of the cost-benefit tests described above and specifies which costs and benefits are included in the calculation for each test.

Some costs and benefits may be captured in an avoided cost designed for general application. For example, avoided costs capture the value of reduced natural gas usage. The inclusion of additional costs and benefits—or adders—in the calculation would reflect those impacts of a DG facility that are better (in the case of benefits) or worse (in the case of costs) than central station facilities or which are not captured by the avoided cost calculation at all.

Most parties agree with the basic list of costs and benefits identified by the Commission and reflected in the Itron Framework. However, the parties did not agree on specific values proposed for use in the SPM tests. We now turn to a detailed discussion of the disputed areas.

5.1. Utility and Program Administrator Costs

The utilities and the Itron Framework include in their cost-benefit tests the costs incurred by the utilities or program administrators for managing DG programs.[13] No party opposed inclusion of these costs in the RIM, TRC, and Societal tests and we include them in the models we adopt today. CCDC, however, believes PG&E's interconnection costs are overstated and asks the Commission to inquire as to why those costs exceed the charges to DG customers.

The administrative costs that should be included in the SPM tests should be current actual program administrative costs, including any interconnection costs, as reported by the SGIP and CSI program administrators in their quarterly reports to Energy Division. With regard to CCDC's concerns about interconnection costs, one suggestion was to rely on expected CEC research on interconnection costs rather than utility estimates, but that research has not been completed. Therefore, we direct that where actual, project specific data on interconnection is available, it should be used. Where it is not available, we will rely on utility data of actual aggregate or program-wide interconnection costs. We direct the utilities and program administrators to develop data collection capabilities and work with Energy Division to provide the necessary cost

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[13] The CSI and SGIP programs are administered by the utilities in the PG&E and SCE territories and by the CCSE in the SDG&E territory.

information, including interconnection costs, to enable us to apply the SPM tests and cost-benefit methodology as soon as possible. After our first cost-effectiveness review of DG programs is complete and to the extent parties still dispute these utility interconnection costs, the ALJ or assigned Commissioner may solicit further comments, or hold workshops or hearings to resolve such disputes and refine this variable in the future cost-benefit tests accordingly.

5.2. Line Losses

DG facilities reduce utility line losses because the energy resource is at the customer's premises, or is in or near a load center, and therefore does not need to be transported over transmission lines. There is some debate about how to reflect a project's size in the cost-benefit calculation. SDG&E/SCG observes that the cost-benefit calculation could make simplifying assumptions for small projects. For projects more than 100 kW, SDG&E/SCG suggests that engineering studies are required to calculate avoided transmission and distribution (T&D) costs and line losses.

In D.07-09-040,[14] the Commission noted that line loss adjustments could be determined in accordance with the methodology adopted in D.01-01-007, and declined to modify the line loss adjustment calculation. (D.07-09-040, at 75.) While we had initially considered using the line loss methodology adopted in D.01-01-007, parties commented in response to the proposed decision that the data required for the methodology adopted in D.01-01-007 is no longer available from the California Independent System Operator (CAISO). Solar Alliance and FuelCell Energy suggest we estimate line losses using the system-wide line loss

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[14] D.07-09-040, *Opinion on Future Policy and Pricing for Qualifying Facilities*, September 20, 2007, R.04-04-003/R.04-04-025.

assumptions in the E3 Avoided Cost Calculator. We agree that this approach is reasonable, and we will adopt that suggestion.

5.3. T&D Investment Deferrals

The Commission has found that DG facilities can reduce the need for new investment in utility T&D facilities. D.03-02-068 adopted several criteria for assessing the extent to which a DG facility might receive payment from a utility to substitute for T&D investments, among them the requirements that the facility be operating in time for the utility to avoid system expansion, that it must be of a size that serves the utility's planning needs, and that it provide a "physical assurance" that the customer will not ever require the utility service that would have otherwise been provided over the deferred investment. (*See* D.03-02-068, at 18.) Thus, D.03-02-068 adopted criteria for contracts between DG owners and utilities for T&D investment deferrals, which are site-specific. The decision does not discuss recognition of T&D deferral benefits for DG projects collectively.

CCDC and ASPv believe cost-benefit models should identify T&D investment deferrals as among the benefits of DG, notwithstanding the specific characteristics of an individual facility. CCDC makes a distinction between DG that is incorporated into a utility's resource plan and affords the utility distribution system benefits (i.e., "grid-side DG") and DG that is analogous to energy efficiency and is not included in a utility's resource plan (i.e., "customer-side DG").[15] CCDC states that there is no basis for applying the strict physical assurance requirements adopted in D.03-02-068 to customer-side DG, and requests that a more flexible approach be adopted for this proceeding.

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[15] CCDC Opening Brief, 6/27/05, at 16.

CCDC argues that the Commission should rely on the diversity of DG projects rather than physical assurance in evaluating customer-side DG avoided costs because these customer-side DG projects, when viewed collectively, are likely to have very strong reliability benefits as shown for DG cogeneration projects, and the probability of simultaneous forced outages is very low. ASPv proposes to measure the physical assurance of DG projects at the program or portfolio level, which would recognize the combined value of the state's DG facilities. ASPv believes that even a single DG facility provides value to the system in terms of avoided T&D usage, although it does not estimate that value. CAC/EPUC asks the Commission to assure that large cogeneration plants receive recognition for transmission and distribution investment deferrals.

SDG&E/SCG, PG&E, and SCE argue that the inclusion of this benefit is contrary to the Commission's existing policy and that the DG parties have not justified the automatic inclusion of T&D deferrals in cost-benefit calculations for every DG installation. PG&E concedes that such a benefit might at some point be included in cost-benefit methodologies when there is sufficient DG in its territory that system planners can rely on their availability.

SDG&E/SCG believes the Commission should continue to recognize the prospect for DG projects to respond to load growth, recommending that projects be evaluated in the context of the distribution planning process established pursuant to Section 353.5.

Discussion:

The policy we adopted in D.03-02-068 relates to utility control over planning and operations of its T&D system. In that decision, we found that a utility could contract with a DG owner for a deferral of utility T&D investments only in specific circumstances where a DG facility meets our "physical assurance" criteria, that is, it can demonstrate its location, capacity and operational characteristics justify a utility investment deferral. The policy context in D.03-02-068 is payment to specific DG facilities for investment deferrals. In this decision, we turn to the separate and distinct issue of estimating the collective T&D investment deferral benefits of DG in an effort to analyze the net costs and benefits of our DG programs.

We find no compelling reason to change our existing policy regarding contracts for T&D deferrals, as adopted in D.03-02-068, that are relied on for utility resource planning. We intend to measure the benefits of any contracts for T&D deferrals by applying the existing criteria to specific projects, as set forth in D.03-02-068. We concur with SDG&E that this is a matter for consideration on a plant-specific basis and consistent with each utility's distribution planning process and D.03-02-068.

That being said, we can still include in our DG cost-benefit methodology an estimation of collective DG T&D investment deferrals, including DG facilities that do not meet the physical assurance criteria. It would be unnecessarily restrictive to apply the physical assurance criteria from D.03-02-068 since many smaller DG projects are not required to meet these criteria to interconnect. We agree with CCDC and ASPv that a more flexible approach is needed for cost-benefit evaluation purposes to measure the collective benefit of DG facilities. It is possible to consider the diversity of installations and the collective benefit to the T&D system of high DG penetration levels in certain geographic areas. Therefore, we find it reasonable to attempt to measure a T&D deferral benefit based on DG penetration, location, and diversity levels.

Itron's SGIP Year 6 Impact Report uses this approach and demonstrates that a collective measurement of T&D deferrals is feasible when specific characteristics of each DG technology are taken into account.[16] As predicted, there is not a significant value until the DG resource is on-line and properly located. Still, the value should not arbitrarily be set to zero when it can be measured. Thus, we direct that the Itron methodology, which uses the E3 calculator as set forth in the SGIP Year 6 Impact Report, be used to estimate T&D deferrals, if any, for either grid-side or customer-side DG installations, without regard to whether the DG facilities are included in a utility's resource plan. Again, we reiterate that use of this Itron methodology to estimate T&D investment deferrals does not in any way modify the specific physical assurance or other requirements in D.03-02-068 for contracts between DG facilities and utilities for distribution capacity deferrals. In addition, this estimation of collective T&D benefits is not intended to prejudge any other Commission proceedings regarding prices for wholesale DG.

5.4. Electricity Market Price Impacts

Some parties propose that the cost-benefit calculation recognize lower electricity market prices that might occur as a result of a DG project's operation. This effect is also referred to as "price elasticity of demand." The Itron Framework includes a price elasticity adder in its Societal and RIM tests, in accordance with the E3 avoided cost methodology.

SCE, SDG&E/SCG, and PG&E oppose including a variable for market price impacts in the equation. SCE contends that DG can reduce market prices in

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[16] See Section 5.3 "Transmission and Distribution Impacts," SGIP Year 6 Impact Report, Itron, August 30, 2007. The Itron methodology uses the E3 calculator and compares DG facility hourly generation profiles against hourly distribution line loadings. For each technology, a reliability curve is developed based on the measured data to produce a probability of achieving a given amount of load reduction.

the near term if penetration of DG is not anticipated by the wholesale electricity market and oversupply results. However, SCE further contends that if the Commission's resource adequacy requirements assure the proper investment in new resources, DG simply offsets new construction and there should be no lasting effect on market prices. (SCE Comments, 2/25/09, at 8.) The Solar Alliance observes that the E3 methodology included a price elasticity adder in the years when new supply-side resources were assumed to not be needed. At this time, since the California utilities are actively adding resources according to their adopted long-term procurement plans, the Solar Alliance agrees there is no need for a price elasticity adjustment in the RIM and Societal Tests. (Solar Alliance Comments, 3/9/09, at 15.) We find these arguments persuasive, namely, that if DG resources are planned, we should not assume their addition will impact market prices. Therefore, we will not include a price elasticity adder in the RIM, TRC or Societal Tests.

5.5. Reliability Impacts

The Itron Framework includes a reliability adder from the E3 avoided cost methodology. Some parties agree that the cost-benefit calculation should include increased system reliability as a benefit. Conceptually at least, DG may improve system reliability under certain circumstances, for example, by providing a dispersed and versatile source of power supply. On the other hand, those reliability benefits could be offset by the unpredictability of a DG customer's need for power from the utility's system or an operator's decision to shut down the generator when market prices are low.

SDG&E/SCG states that enhanced systemwide reliability is unlikely but concedes that DG has the potential of reducing reliability costs for a utility where DG reduces peak load in constrained areas. It believes these benefits will be nearly zero by 2010, however, when new generation is expected to come on-line. SDG&E/SCG also states that DG does not have the control capabilities to provide ancillary services and should therefore be treated as load reduction for purposes of ancillary services and VAR support, as Itron proposes. SDG&E/SCG proposes the Commission use the values presented in the E3 report and adopted in D.05-04-024.

PG&E believes the avoided cost calculation reflects a DG facility's value as a generation resource generally, although it does not assign more or less reliability to the DG facility than a central station facility. In comments on the proposed decision, PG&E asserts that the E3 reliability adder is "overly optimistic" and suggests further study is necessary before it is used. (PG&E Comments, 7/9/09 at 9.)

CCDC concurs that quantifying the value of DG to the transmission system will not be possible immediately and proposes the utilities be ordered to conduct a transmission system simulation to determine those potential benefits. The utilities oppose such an effort as time consuming and expensive, and believe this type of task is part of the CAISO's transmission system planning process. CCDC also recommends that the Commission adopt E3's estimate for transmission reliability improvements by DG during peak hours.

The extent to which DG projects can improve reliability is unclear. Nevertheless, we believe that, on balance, DG facilities may relieve the strain on some critical elements of the utility system, as SDG&E/SCG observes. The Itron Framework proposes using the same E3 reliability adder which values reliability benefits from demand reductions and is currently used for evaluation of energy efficiency programs. Use of the existing E3 reliability adder assumes reductions in demand caused by DG have at least roughly the same reliability impacts as changes in demand caused by energy efficiency or any other source of fluctuation. We will include the reliability adder in the E3 avoided cost methodology we use in our SPM tests, as suggested in the Itron Framework, at least for now.

At the same time, it is worth noting that in the Commission's Resource Adequacy rulemaking (R.08-01-025), the Commission adopted a new methodology for analyzing the peak load contributions of utility-scale renewable generation from intermittent resources, such as wind and solar power plants.[17] The outcome of this new methodology in the Resource Adequacy context could impact our findings here on how to incorporate reliability assumptions for intermittent DG resources into our cost-benefit analysis. We will direct our Energy Division to further study whether the outcome of that proceeding affects our decision here to use the E3 reliability adder. After such further study, Energy Division should report to the ALJ and assigned Commissioner whether modifications to this decision are necessary, and the ALJ and assigned Commissioner will determine if further Commission action is needed.

DG facilities may also improve the reliability of the DG customer because of its value as back-up power or voltage support. We do not have estimates of the value of a DG facility to the customer who owns it. To the extent the utility or the project developer has developed an estimate for each project and this information is readily available, it may be reported by program administrators as additional useful information, but we will not incorporate this information into the cost-benefit tests at this time.

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[17] See D.09-06-028, Section 4.10, in R.08-01-025.

5.6. Employment and Tax Revenue Effects

DG proponents propose the Commission include increased employment and tax revenue as among the benefits of DG. The utilities argue, however, that we have no evidence from our current record in this proceeding to suggest that DG installations would create more jobs than those displaced as a result of the reduced demand for central station generation facilities. At this time, therefore, we cannot quantify a variable for increased employment or tax revenue for inclusion in our cost-benefit models.

Nevertheless, we see value in working towards quantifying an employment and tax revenue effect from our DG programs. We recognize that DG projects, particularly solar installations through our CSI program, have created jobs in California for the past several years. On the other hand, we lack any quantification of how this job creation compares to potential reductions in jobs at the utilities to build central station generation or other facilities. As part of our program evaluation plan for CSI, we intend to examine employment effects of our CSI program. At the same time, we will require the contractor performing the DG cost-benefit analysis to suggest a methodology for quantifying the employment and tax revenue effects of our DG programs so that parties can comment on this area further. Once the contractor has suggested a methodology, the ALJ can solicit comments or hold a workshop on this topic to consider whether to include these effects in future cost-benefit analyses. This quantification of employment or tax effects should not be included in the SPM tests until further Commission proceedings are held on this topic.

5.7. Market Transformation Effects

Some DG Proponents propose the Commission treat DG development as a "market transformation" program and that the cost-benefit calculations include market transformation effects as a benefit. Market transformation in this context refers to development of a self-sustaining market for DG whereby customers have a wealth of potential suppliers of DG and can make independent and free-ranging choices about DG installation. We would also expect a transformed market to need minimal or no public subsidies in order to remain competitive and support multiple providers and options for consumers. PV Now explains that the models presented in this proceeding are narrowly defined to promote immediate resource acquisition and do not take into account the more important long-term objectives of assuring that photovoltaic technologies, in particular, are sustainable in competitive markets without subsidies. CalSEIA, the City of San Diego and ASPv offer similar comments.

SCE and SDG&E/SCG object to recognizing market transformation objectives in cost-benefit models, claiming that attempts to measure the market transformation effects of DG would be expensive and unjustified. They also believe the SGIP program has been developed as a resource acquisition program rather than one that is intended to have long-term market impacts. We disagree.

This Commission has stated its strong support for solar photovoltaic generation and other DG technologies as part of a larger effort to promote the development of a diverse and environmentally sound energy production system. For example, in D.06-01-024, where the Commission established the CSI program, the Commission explicitly acknowledged that solar technologies may not be cost-effective yet, but determined that an incentive program was justified as a means of market transformation. In D.06-01-024, the Commission stated:

> Our decision today is informed by our view that a common sense program of monetary incentives, combined with technical assistance, could promote less expensive and more efficient technologies. We also approach our task here with the

> understanding that solar technologies may not be as cost-effective as other clean alternatives, in particular energy efficiency efforts and certain other renewable distributed generation technologies. However, a solar incentive program will aid California's transition to an affordable clean energy portfolio. We are convinced that a cost-effective and sustainable solar market is unlikely to develop without a commitment for market support that is both long-term and finite. For that reason, we state our intent to monitor the progress in the market place, and to modify the program on the basis of ongoing evaluation. (D.06-01-024, at 4-5.)

Similarly, Senate Bill (SB) 1, the legislation codifying the CSI program, acknowledges the resource acquisition goal for CSI, but further declares that it is the goal of the state "to establish a self-sufficient solar industry in which solar energy systems are a viable mainstream option for both homes and businesses in 10 years."[18] It appears both the Commission and the Legislature view the CSI as a market transformation program, at least in part. Therefore, we find that market transformation benefits are legitimately included in a cost-benefit evaluation of DG programs.

Moreover, the Commission has expressed support for DG in the Energy Action Plan, requiring DG to be deployed ahead of other energy production technologies. The SGIP program is explicitly designed to promote DG development, as are several tariff exemptions or discounts for DG operators and customers.

There is no question that the Commission has take action directly supporting the development of a viable market for DG projects, especially those using renewable resource technologies, as alternatives to energy facilities employing fossil fuels, coal and nuclear resources. Notwithstanding the short-term goals of the SGIP and CSI programs, we believe the programs will and should influence the types of energy technologies deployed in California and the structure of the state's energy production and delivery system.

The value of "market transformation" is neither specified nor quantified in the early record of this proceeding. Subsequently, Itron produced a report in February 2007 entitled "Solar PV Costs and Incentive Factors" (Solar Cost Report)[19] that examines the key relationships between solar PV performance, cost, and incentive levels. The report includes an assessment of the impact of incentive levels on program results based on different funding scenarios. Itron's Solar Cost Report finds that these forecast scenarios illustrate the impacts of performance and cost factors on program goals and incentive design. (Exhibit 39 at 2-2.) In addition, E3 provided to Energy Division a discussion draft in May 2007 entitled "SGIP Market Transformation Effects Evaluation Methodology." This E3 draft suggests a method for forecasting the future cost-effectiveness of SGIP and then evaluating the attribution of cost reductions to SGIP (i.e., the "market transformation" effect of the program) through a learning curve analysis, expert interviews, and literature review.

The Itron Solar Cost Report and the E3 draft indicate to us that there are reasonable methods to estimate the market transformation effects of our DG programs. Now that we have several years of SGIP data, and after CSI has been

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[18] See Section 4 of SB 1 (Ch 132, Stats of 2006), which adds Section 25780(a) to the Public Resources Code.

[19] "CPUC SGIP: Solar PVCosts and Incentive Factors," Itron Inc., February 2007 (Exhibit 39).

operational for a few years, it may be possible to use either the Itron scenario approach or the E3 method to perform qualitative assessments of the market transformation effects of our programs. Therefore, we direct Energy Division to ensure the consultant who performs the cost-benefit analyses of our DG programs uses either of these methods, or a reasonable substitute, to analyze and estimate the market transformation effects of CSI and SGIP. The consultant should first perform the SPM tests without any market transformation analysis, and then conduct a second set of the SPM tests that incorporates a market transformation component. The purpose of the market transformation assessment is to demonstrate if or when the incentive program for a DG technology is cost effective and the market significantly transformed, or when the program is expected to be cost-effective, under the different SPM tests given a variety of scenarios. We expect the overall cost-benefit analysis to include an assessment of the progress towards the goal of market transformation, and an analysis of how the cost-effectiveness test results might be expected to change as the markets for various DG technologies evolve.

We acknowledge that any market transformation analysis will involve scenario analysis and a host of assumptions. Among other things, these assumptions will likely include varying levels of future total installation costs for DG. Parties will undoubtedly want an opportunity to examine and critique the analysis. Therefore, we anticipate that after a consultant performs a market transformation analysis as part of the cost-effectiveness review of our DG programs, the ALJ or assigned Commissioner may choose to hold workshops, hearings, or solicit comments to consider refinements to the market transformation analysis.

5.8. Reduced T&D and Commodity Revenues

The Itron Framework includes measurement of decreased T&D revenues and foregone commodity revenues from reduced sales of electricity or natural gas. PG&E and SCE contend that when a customer installs DG, there is a resulting loss of T&D and commodity revenues by the utility and this "lost revenue" is borne by other customers through the process of revenue allocation and rate design. PG&E believes these reduced revenues should be included in the Participant Test (as a benefit) and RIM Test (as a cost to ratepayers), but not the TRC or Societal Test.

CAC/EPUC objects to including purported "lost" revenues as a cost, believing that lower revenues are offset by lower costs. CAC/EPUC also believes the Commission should follow the Federal Energy Regulatory Commission (FERC) precedent and assume that such lost revenues are normal business risk. PG&E responds that T&D costs are generally fixed and ratepayers remit T&D revenues on a volumetric basis. In addition, the RIM test does not measure losses to the utility but to ratepayers. Even if T&D costs fell, ratepayers would not receive the benefits of lower costs between general rate cases.

The Solar Alliance and IREC claim the RIM test should not include reduced commodity revenue because the utilities should have followed Commission directives and included DG in their long term procurement planning.

Under existing ratemaking, the Commission authorizes a distribution and non-fuel generation revenue requirement for each utility, and then sets rates based on a forecast of sales. If sales are lower than the forecast, the difference is tracked and the utility's ratepayers must ultimately make up any reduced revenues to allow recovery of the authorized distribution and non-fuel generation revenue requirement. Transmission rates are regulated by FERC, and if a utility's sales differ from forecast, it will see reduced transmission revenues and most likely seek rate adjustments in its next transmission rate case at FERC. Accordingly, this is not a case where utility "business risk" is an issue. The risk is ultimately borne by the ratepayer. As customers install DG and no longer pay these charges, non-participating ratepayers may ultimately see higher charges. Therefore, in order to ensure an accurate assessment of how DG facilities affect ratepayers, we agree that reduced transmission, distribution and non-fuel generation revenues should be included as a cost in the RIM test, and as a benefit in the Participant Test. The benefit included in the Participant Test is measured as the exemption from standby charges, which is discussed further in Section 5.12 below. The estimates for these costs to ratepayers would be based on actual utility rates and the DG output from facilities installed under our incentive programs, as derived from utility rate tariffs and DG production data.

In addition to distribution and non-fuel generation charges, the utilities recover their actual purchased power and fuel related generation costs (also called procurement or commodity costs). Solar Alliance and IREC raise a valid point that utility procurement costs already factor in a DG load forecast. As a utility's sales drop, the utility presumably buys or generates less power or gas and incurs lower costs. In other words, the commodity revenue a utility "loses" would simply have paid the fuel or purchased power cost the utility did not have to buy or generate. There is no need to include reduced commodity revenue as a cost if the cost is avoided. Moreover, if a utility buys less power or fuel for a smaller customer base, it is not a given that the remaining customers will pay a higher cost. It would be speculative to assume that reduced commodity revenues translate into a cost for non-participating customers.

5.9. DG Project Costs

All parties agree that the costs of installing and maintaining DG units should be included in the Participant Test and the Societal Test. We agree that this is appropriate.

CalSEIA proposed to measure DG project costs using estimates of future costs at lower levels than that presented in existing databases. SDG&E/SCG believes the Commission should use data collected from the SGIP and the CEC's Emerging Renewables Program (ERP). SDG&E/SCG observes that this data are derived from actual facilities' costs.

We have no basis upon which to forecast future technology costs and we are not convinced that future costs provide an appropriate proxy for current project costs. We intend to use actual data to measure the costs of DG projects. As costs fall, they will be reflected in the databases. The SGIP and CSI programs both have project tracking databases that reflect project costs and this actual program data should be used. The CEC retains some data tracking such costs associated with solar photovoltaic projects, which could be used as well. Otherwise, estimates available through manufacturers for specific technologies should be included in the analysis.

5.10. Environmental Values—CO2, NOx, and PM 10 Emissions

The Itron Framework describes how DG, in displacing conventional central station generation, may have environmental impacts. To the extent these environmental impacts are not internalized by the marketplace, the Itron Framework suggests a method for placing a value on these impacts and including them in the Societal Test. The method suggested in the Itron Framework relies on the E3 environmental adder, derived from the E3 avoided cost calculator. The Itron Framework notes this has been a fairly standard practice in California when assessing energy efficiency options.

The utilities generally support the use of the E3 calculator for generation and fuel to recognize air quality improvements from DG.[20] The E3 data incorporates reductions in carbon dioxide (CO2), nitrogen oxides (NOx) and particulate matter 10 (PM 10) emissions.

CCDC would modify the E3 environmental adder by reflecting the actual mix of existing and expected power plants and their operating characteristics rather than using futures prices to estimate electricity market prices. The CCDC estimate would affect emission costs for CO2, NOx and PM 10. CCDC states that the dirtiest power plants are those most likely to be used during peak periods, and these marginal units should be included in the model, at least for the early years of a DG project. CCDC recognizes that emission avoided costs should be tailored by DG technology, time period, and facility location. CCDC also believes the E3 Report's use of the New York Mercantile Exchange (NYMEX) futures prices does not accurately reflect California conditions and an environmental adder would improve the price estimate in that regard.

We will not adopt CCDC's proposed modification to the E3 environmental adder at this time. As we have previously noted, D.06-06-063 updated natural gas and generation costs for the E3 calculator and its environmental adder. These updated avoided costs and environmental adder are used when

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[20] PG&E initially argued in its 2005 testimony and briefs that no value should be given to DG environmental effects if they are not regulated or their mitigation mandated. PG&E states in its July 2009 comments on the proposed decision that it has dropped this position and it now agrees that environmental values used in other Commission avoided cost proceedings should also apply to DG, both as potential costs and benefits.

evaluating energy efficiency programs, and we conclude that we should apply the same method when evaluating DG in order to compare resource options with a consistent set of avoided costs. As environmental values used for cost-effectiveness evaluations of energy efficiency programs are updated, the same updates should be applied here.

PG&E believes that DG facilities may increase CO2 emissions relative to central station plants because modern plants burn fuel at a much higher heat rate. It therefore proposes that this impact be included as a net cost of DG facilities.

We wish to capture all benefits attributable to DG facilities and, in particular, to recognize those that improve environmental quality. In addition, we note that the method proposed in the Itron Framework includes modification of the E3 environmental adder for individual technologies to reflect the net CO2 impacts of DG. We find this approach addresses PG&E's concern that we capture the net cost of DG facilities.

We herein adopt the Itron Framework's method for valuing environmental benefits along with the updated avoided costs from D.06-06-063, which incorporate environmental values for CO2, NOx, and PM 10, for use in the TRC, Societal, PA Cost, and RIM tests. Again, as these environmental values are updated by the Commission for use in energy efficiency evaluations, the same values should be applied in DG cost-effectiveness tests.[21]

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21 We note that the California Air Resources Board, in its Climate Change Scoping Plan adopted December 11, 2008, has stated its intention to implement a cap and trade program beginning in 2012 to limit total GHG emissions from covered sectors consistent with Assembly Bill 32, the California Global Warming Solutions Act of 2006. Under this framework, emission allowances would be issued such that the sum of total emissions

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5.11. Combined Heat and Power Applications

CCDC proposes that the E3 avoided cost estimate for fuel and generation be modified to recognize that cogeneration uses a single fuel to produce electricity and production heat. SDG&E/SCG agrees that this benefit would always accrue to the DG customer and may represent a societal benefit if the efficiency of the DG facility is higher than a central station plant. SDG&E suggests these benefits would be plant-specific and believes the Itron Framework appropriately accounts for them.

We agree that the Participant, TRC, and Societal Tests should include a value that recognizes more efficient use of cogeneration facilities, where appropriate. We will direct that these tests include an estimate of the related plant-specific characteristics. This approach was described in Appendix A3 of the Itron SGIP Evaluation Report (dated September 2005) and in the SGIP Year 5 and Year 6 Impact Reports (dated March and August 2007, respectively).

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would not exceed the level of the cap. Because the deployment of renewable DG will not change the number of allowances in circulation once the cap goes into effect in 2012, these facilities may not result in emission reductions below the level of the cap. While the deployment of clean DG will reduce the carbon liability of the electricity sector, thereby reducing the number of allowances the electricity sector needs to purchase to cover its carbon liability, these allowances would presumably be procured by other entities such that total emissions under the cap remain unchanged. As such, while from the perspective of the electricity sector, the costs of these emission permits will be avoided, from a societal view, there may be no reduction in GHG emissions or their costs. To the extent the Itron framework ascribes a specific value to the societal benefit of avoided GHG emissions from DG, the methodology may require adjustments to account for the implications of a cap and trade system on the ability of DG deployment to change total emissions. We do not take steps to amend the methodology and address this issue at this time, but we reserve the right to evaluate whether further adjustments to environmental impact values are necessary to account for the implementation of a cap and trade program.

5.12. Standby Charges

The Itron Framework includes the loss of revenues from exemptions from standby charges as among the costs that should be included in the RIM Test. SDG&E/SCG concurs with this methodology and suggests estimating this cost using data it has collected as part of the SGIP program.

SCE believes that if the revenue shortfall from standby charges is not offset by total DG benefits, Section 353.9 requires that the shortfall be recovered from members of the DG class only.

We agree that this standby charge exemption should be included as a cost in the RIM Test, because it represents a revenue loss, and also as a benefit in the Participant Test. Estimates would be derived using the utilities' rate tables and according to the DG facilities' production. We also agree in principle with SCE's observation that any revenue shortfall requires recovery according to the terms set forth in Section 353.9. This latter issue involves revenue allocation, which is outside the scope of this proceeding. We therefore defer this matter to proceedings that allocate revenues among rates and customer classes. For SCE and PG&E, this would be in their respective general rate cases. For SDG&E, this could be in its general rate case or "rate design window" application.

In comments on the proposed decision, IREC raises the concern that including standby charge exemptions as a cost in the RIM and PA Cost Tests could result in double counting of lost T&D revenues. (IREC Comments, 7/9/09 at 3.) PG&E acknowledged this concern in earlier comments. (PG&E Comments, 3/9/09 at 9.) We recognize the complexity of electricity ratemaking and the difficulty, at times, in deciphering actual standby costs. Despite this complexity, we agree with IREC that it is important to not double count costs. To the extent standby charge exemptions are already included as lost revenues, as discussed in Section 5.8 earlier in this decision, they should not be counted twice.

Similarly, Solar Alliance comments that including standby charge exemptions as a cost is inconsistent with current studies of the diversity benefits of standby customers. (Solar Alliance, 7/9/09, p. 7.) We disagree with this comment, because the cost-benefit methodology we adopt in this decision already incorporates benefits of the diversity of DG facilities through efforts to quantify T&D deferral benefits and reliability benefits of DG.

5.13. Electric and Natural Gas Avoided Costs

The parties generally agree that DG facilities allow the utilities to avoid commodity and capacity costs for electricity and natural gas. SDG&E/SCG proposes that we adopt the E3 values adopted in D.05-04-024. SCE and PG&E would apply those values until the Commission has modified them for DG in a later phase of that proceeding. In D.06-06-063, the Commission refined the interim avoided costs adopted in D.05-04-024.

As stated in Section 3.2, we herein adopt the E3 avoided cost methodology for electric and natural gas avoided costs, as adopted in D.05-04-024 and updated in D.06-06-063, and with the inputs currently applied to energy efficiency evaluation. These avoided costs should be used in the DG cost-benefit analysis as set forth in Attachment A of this decision.[22]

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[22] We note that the E3 calculator may not fully reflect the value that customer-side DG, or other demand side resources, provide in terms of reduced renewable energy obligations. By reducing a utility's retail sales, which serve as the basis for determining a utility's renewable procurement needs, these customer-side resources lower the amount of renewable energy that needs to be procured, all else equal. To the extent that renewable resources are more expensive than conventional resources, we believe

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5.14. Net Metering

Certain renewable DG projects qualify for "net metering," which permits a DG operator to receive bill credits for electricity delivered to the utility. Under net metering, a DG customer will receive bill credits when the DG system is producing more electricity than the customer needs. These bill credits may be applied against charges incurred by a DG customer for electricity consumed at other times. For solar DG less than 1 MW and wind DG less than 50 kW, the amount of the net metering bill credit is equal to the fully bundled retail rate of electricity that the customer would otherwise pay.[23] The fully bundled net metering credit includes a generation component as well as a T&D component. The fully bundled net metering credit amounts to a payment-in-kind that can be substantially in excess of the avoided cost the utility would otherwise pay to procure electricity and that a DG facility would otherwise receive for selling wholesale power to the utility. Moreover, DG customers who qualify for net metering credits still use the T&D system to export energy to the grid.

Because bill credits under net metering are a subsidy from ratepayers to DG facilities, SDG&E/SCG proposes to include them as a cost in the RIM Test.

We agree with SDG&E/SCG that bill credits under net metering are an incentive designed to promote DG development, and we agree that energy exported to the grid by DG facilities in excess of their annual load is a benefit of

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there may be some value that DG and other demand side resources provide that is not being fully quantified. While we do not address this issue specifically here, Energy Division will work with E3 to ensure that in the future this value is fully and appropriately incorporated into the E3 calculator.

net metering. Because we are able to measure both bill credits under net metering and energy exports, we intend to include both the costs and benefits of net metering in the appropriate tests. Net metering bill credits are a cost in the PA Cost, and RIM Tests. They are a benefit for the Participant Test. By the same token, energy exports are a benefit for the PA Cost, and RIM Tests. However, the benefit of energy exports should already be included in the tests when DG production is calculated and energy purchases are avoided based on that calculation. To the extent the tests already calculate avoided costs based on estimated DG production, we should not include a separate variable for energy exports or we would count the benefit twice. Finally, NEM costs and benefits represent transfers in both the TRC and Societal Tests, and are therefore omitted from these tests.

5.15. Exemptions from the Cost Responsibility Surcharge

The Cost Responsibility Surcharge (CRS) permits the collection of power purchase liabilities incurred by the Department of Water Resources (DWR) during the state's energy crisis, which are generally more expensive than market prices. DG projects under 1 megawatt (MW) and the first MW of clean DG units that do not exceed 5 MW are exempt from the CRS. (See D.07-05-006.)

The utilities argue that the RIM Test should reflect the loss of CRS revenues when a DG facility goes on-line, as the Itron Framework recommends.

[23] For larger wind DG (greater than 50 kW, but less than 1 MW), biogas DG less than 1 MW and fuel cell DG less than 1 MW, the amount of the net metering bill credit is equal to the generation component of the rate only.

CAC/EPUC believes the RIM Test should not include reduced CRS revenues because DWR did not purchase power for DG customers and small DG customers are exempt from CRS charges. CCDC makes similar comments.

CAC/EPUC is correct. Lost revenues associated with exemptions from CRS should not be accounted for in the RIM Test. In developing its strategy for purchasing power during California's energy crisis, DWR believed that it could rely on a forecasted amount of DG power to meet the state's energy demand and purchased power supplies accordingly. For that reason, we found in D.03-04-030 that certain DG facilities should be exempt from the CRS. D.03-04-030 found that DWR excluded 3,000 MW of power for DG from its forecast, and therefore the exemption is not a cost shift. For this reason, we conclude that lost CRS revenues should not be considered a cost in the RIM Test.

5.16. SGIP and CSI Incentives

Currently, both the CEC and this Commission sponsor incentive programs for renewable DG projects through SGIP and the CSI. Once we establish that DG facilities should be analyzed using the cost-benefit tests described in this decision, there is no controversy about whether and how to recognize these incentives in the models. As the utilities suggest, these incentive payments are appropriately considered a cost in the TRC, Societal, RIM, and PA Cost Tests and as a benefit in the Participant, TRC, and Societal Tests. The incentive amounts are available through the program rules and databases and are readily applied according to facility characteristics and performance.

5.17. Tax Incentives

Both the state and federal governments provide tax incentives for certain types of DG projects. No party opposes recognizing these subsidies in the models. They should be included as benefits in the Participant Test.

For both the TRC and the Societal Test, federal tax incentives should be included if we define the relevant "society" as California and the benefit of these incentives flows into California from federal taxpayers. State tax incentives would *not* be included because they are merely transfers within California.[24]

Tax incentives should be estimated using Internal Revenue Service regulations and State Franchise Tax Board rules, or the information provided by DG vendors.

6. Program Monitoring, Measurement, and Evaluation

The DG cost-benefit methodology adopted in this decision shall be used to evaluate our ratepayer supported DG programs, namely the SGIP and CSI incentive programs, which involve support to DG facilities up to 5 MW in size. Authorized funding for the portion of CSI overseen by this Commission amounts to $2.16 billion in expenditures from 2007 through 2016, all provided by utility ratepayers. The current funding level for SGIP is $83 million per year, also paid by utility ratepayers. The methodology adopted herein will allow the Commission to measure the costs and benefits of our DG programs. This will be one element of measuring the success of various SGIP and CSI program elements and allow the Commission to tailor incentives accordingly.

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[24] If the TRC or Societal Test were performed with the relevant society defined as one utility's service area as opposed to statewide, then state tax incentives could be treated as a benefit. At this time, we choose to run the TRC and Societal Tests based on a statewide definition of society in order to evaluate our DG programs on a statewide basis.

With regard to CSI, a detailed Program Evaluation Plan was established in a July 2008 ruling.[25] The CSI evaluation plan, as set forth in Appendix A of that ruling, includes cost-effectiveness studies which shall be conducted periodically using the methodology adopted in this decision. (*Id.*, Appendix A, Section 3.3.6.) The CSI evaluation plan calls for the first cost-effectiveness studies to be completed in early 2009, evaluating 2007 and 2008 program data. Energy Division may either contract directly with an independent entity to perform this cost-effectiveness analysis, or it may direct the CSI program administrators to contract for the work. (*Id.*, Section 1.3.) A Project Coordinator will work closely with Energy Division staff to facilitate this program evaluation effort. (*Id.*, Section 3.3.1.) We herein direct our Energy Division to ensure the cost-effectiveness studies of CSI are performed according to the guidance and methodology set forth in this decision. Energy Division should initiate efforts to retain a contractor to perform these studies within 30 days from the date of this order.

We direct the utilities and SGIP and CSI program administrators to obtain, facilitate the obtainment of, or supply all program data, participant (or DG customer) data, or other relevant information requested by Energy Division, or its contractor, for this analysis.

For SGIP, we direct our Energy Division to ensure the SGIP administrators hire independent contractors within six months of this order to perform a cost-effectiveness analysis of SGIP for all prior program years.

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[25] *See "Assigned Commissioner's Ruling Establishing Program Evaluation Plan for the California Solar Initiative,"* R.08-03-008, July 29, 2008.

For both SGIP and CSI, we will review the results of the SPM tests discussed in this decision – namely the Participant Test, Program Administrator Cost Test, TRC Test and Societal Test – and not specify a primary test. We prefer to include the perspective embodied by each of these SPM tests in the overall evaluation of DG programs. Together, these SPM cost-benefit tests can be a tool to assist in ongoing program evaluation and to suggest improvements in design and administration of ratepayer-supported DG programs in the State.

The Energy Division should oversee the cost-effectiveness analysis work to ensure the appropriate application of the methodology described herein. If data to perform the tests described in this decision is not readily available, or if it is cost-prohibitive to obtain it, Energy Division may exercise its discretion and direct the contractors to use alternative data sources. Any such deviations from the data sources described in this decision and Attachment A must be transparently communicated and justified in the resulting study. Energy Division and its contractor should seek to obtain the most recent data available to ensure accurate analyses.

Once the cost-effectiveness analysis work is complete, the ALJ shall allow parties an opportunity to comment on the completed analysis and, in consultation with the assigned Commissioner, shall hold additional workshops or hearings as deemed necessary to consider refinements or modifications to any portion of the analysis.

While the Commission's primary purpose in adopting this methodology is to assess ratepayer-supported DG programs, the Commission may wish to apply this methodology to evaluate other forms of DG, in addition to those funded through the SGIP and CSI programs. The Commission may, at a future date or in another proceeding, explore application of this methodology to other forms of

DG. At such time, the Commission may consider whether modifications to any cost or benefit inputs are needed to fulfill that purpose.

7. Comments on Proposed Decision

The proposed decision was initially issued for comment on September 6, 2005, in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on September 26 and 30, 2005. Subsequently, the proposed decision was withdrawn from the Commission's agenda. The decision was revised and reissued for comment.

The proposed decision of the commissioner in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by CCDC, CCSE, CESA, DRA, FCE, IREC, PG&E, the Solar Alliance, SCE, and SDG&E/SCG. Reply comments were filed by CCDC, CCSE, FCE, IREC, PG&E, the Solar Alliance, and SCE.

Where the comments suggested minor adjustments or clarifications to the decision, these have been incorporated throughout. Where comments reargued earlier positions or attempted to present new arguments or facts, they were not considered.

A few comments merit discussion. Several parties commented that there were errors in the discussion of how to include T&D investment deferrals in the methodology. That section of the decision has been revised to remove the distinction between grid-side and customer-side DG. In addition, the discussion of the physical assurance requirements of D.03-02-068 has been amended to clarify that while those requirements are intact for purposes of contracts for T&D investment deferrals, the requirements are not applicable to the methodology we will use to estimate collective T&D benefits of both grid-side and customer-side DG.

Solar Alliance and FCE commented that we should attempt to include employment and tax revenue benefits in the analysis. The decision has been revised to direct the contractor to suggest a methodology for quantifying these effects, and to allow for further comments and consideration of this issue.

DRA and FCE ask for additional transparency and opportunity for input as the cost-benefit tests are performed by the contractor, particularly if input variables are modified as allowed in certain circumstances. The decision has been modified to clarify that once the contractor completes the cost-benefit analysis, parties will have an opportunity for comment and the ALJ and assigned Commissioner will determine if further hearings or workshops are necessary following those comments.

Solar Alliance alleges the decision errs in neglecting to include the price elasticity benefits of DG in the natural gas market, although it has included the price elasticity effects of DG in electricity markets. Solar Alliance is incorrect. The decision specifically excludes electricity market price elasticity effects from the cost-benefit analysis, finding that if DG resources are anticipated, we should not assume their addition will impact the market price of electricity. The decision agrees with the parties who claimed that the utilities will procure fewer non-DG resources in response to anticipated DG capacity.

Nevertheless, we agree with Solar Alliance that, in general, the DG resources deployed through our various incentive programs in California should reduce demand for natural gas, and this may result in lower prices for natural gas than might otherwise occur if these DG resources were not deployed. The key question is whether this reduced demand is currently large enough to have a measurable impact on natural gas market prices. Despite our agreement with Solar Alliance that our programs should reduce natural gas demand, we will not direct our consultant to estimate natural gas market price impacts at this time. It is our view that this may be worthy of consideration when DG penetration reaches a higher level. For now, we find the potential market price impact from our programs is too small to justify creating a methodology and isolating this impact from other natural gas market price fluctuations. We can revisit this determination at a later date and direct study of this potential benefit if conditions warrant it.

8. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Dorothy Duda is the assigned Administrative Law Judge (ALJ) in this portion of the proceeding.[26]

Findings of Fact

1. The Commission has an avoided cost methodology, the E3 Calculator, adopted in D.05-04-024 and modified by D.06-06-063, that it can apply to DG cost-benefit models.

2. The RIM test measures the relative costs and benefits of DG projects or programs on utility rates.

3. The RIM Test is not required for evaluation of the cost-effectiveness of energy efficiency programs.

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[26] The issues in this decision were initially heard by ALJ Kim Malcolm as part of R.04-03-017. That rulemaking was closed in March 2006, and the record supporting this order was transferred to R.06-03-004 and then to R.08-03-008 under ALJ Duda.

4. The TRC and Societal Tests each provide a unique perspective to measure the impacts of DG facilities on the state's economy generally and compare DG facilities to other energy resource options.

5. The TRC Test is used by the Commission to evaluate the cost-effectiveness of energy efficiency programs.

6. The Participant Test measures the economic viability of a DG facility to the developer or customer installing the facility and can assist the Commission in determining the level of incentive needed to promote the investment.

7. The PA Cost Test measures the net costs incurred by the PA for DG programs and may be used to evaluate program budgets and expenditures.

8. The Standard Practice Manual methodology was developed to measure resource costs and benefits for many types of resources, including energy efficiency, demand response, and distributed generation.

9. The SPM has been used in the past primarily to evaluate energy efficiency programs.

10. The cost-benefit specifications presented in the Itron Framework were developed specifically to analyze DG facilities.

11. Utility and program administrator costs are reported by SGIP and CSI program administrators in their quarterly reports to Energy Division.

12. In D.01-01-007, the Commission adopted a method to estimate line losses, and affirmed that method in D.07-09-040, but the data needed to support that methodology is no longer available.

13. In D.03-02-068, the Commission adopted "physical assurance" criteria relating to payments to a DG facility might receive if it contracts with a utility for T&D investment deferrals.

14. The E3 reliability adder assumes reductions in demand caused by DG have roughly the same reliability impacts as changes in demand caused by energy efficiency.

15. DG facilities may improve reliability of power supplies to DG customers.

16. The record of this proceeding provides no evidence whether DG facilities increase or decrease the level of employment relative to employment at utility central station generation facilities, but the Commission can conduct further inquiry on these effects and add a variable to the methodology at a later date.

17. The Commission's policy to promote DG as a vital energy resource in the state is consistent with the idea of "market transformation," which assumes the assimilation of DG technologies as an integral part of the state's energy resources. In this proceeding, the Commission has no estimates of the market transformation effects of DG programs, but there are reasonable methods available to perform qualitative assessment of these effects.

18. Including reduced transmission, distribution and non-fuel generation revenues in the RIM Test would estimate the losses to ratepayers when DG customers reduce or eliminate these charges.

19. SGIP and CSI databases provide actual program data to reflect the costs of installing, maintaining and operating DG projects.

20. The E3 environmental adder and avoided costs from D.06-06-063 are used when evaluating energy efficiency programs.

21. Cogeneration plants use a single fuel to produce electricity and production heat, which may be more efficient from an engineering standpoint than electricity production at a central station plant.

22. Exemptions to DG facilities for standby charges are a revenue loss to utility ratepayers, and a benefit to DG program participants.

23. The Commission adopted avoided costs estimated by E3 for electricity and natural gas in D.05-04-024, updated them in D.06-06-063, and specified further input adjustments to this methodology for use in evaluating energy efficiency programs.

24. Bill credits under net metering are an incentive designed to promote DG development.

25. Exemptions from CRS liabilities for DG facilities do not result in a loss of revenues because DWR did not purchase power for DG customers.

26. SGIP and CSI incentive payments represent a cost to utility ratepayers and a benefit to DG customers.

27. Tax incentives represent a benefit to DG customers.

28. The Participant, PA Cost, TRC, and Societal Tests can collectively provide a tool to assist the Commission in the ongoing evaluation of DG programs.

Conclusions of Law

1. The Commission should immediately implement DG cost-benefit tests using the avoided cost methodology adopted in D.05-04-024, as modified by D.06-06-063, and with any input adjustments currently directed by the Commission to be used in evaluating energy efficiency programs.

2. The contractor performing the cost-benefit analysis should document and justify any modifications to the avoided costs to adapt them to DG facilities.

3. The Commission should not require the use of the RIM Test to evaluate DG programs because it is not relied on to evaluate energy efficiency programs.

4. The Commission should require the use of both the TRC Test and the Societal Test to measure the impacts of DG programs on the state's economy generally and to compare DG programs to other energy resource options.

5. The Commission should require the use of the Participant Test to help identify "free riders," that is, those DG projects that would be profitable for DG customers absent all or some portion of existing incentives.

6. The Commission should require the use of the PA Cost test to evaluate the net costs of DG program budgets and expenditures.

7. The SPM cost-benefit tests described in this order should be adopted with the specifications, data and variables set forth herein and as summarized in Attachment A.

8. Current program administrative and interconnection costs as reported by the SGIP and CSI program administrators in their quarterly reports to Energy Division should be used in the SPM Tests as set forth in Attachment A. If project-specific data on interconnection costs is not available, actual aggregate or progam-wide data can be used.

9. Values for line loss reductions should be included in the TRC, Societal and RIM Tests and should be estimated using the system-wide line loss assumptions in the E3 Calculator.

10. In estimating the collective impact of DG facilities on T&D avoided costs, the Commission should not change the requirement for "physical assurance" adopted in D.03-02-068 for a DG facility that receives payments from a utility for T&D investment deferrals.

11. It is reasonable to estimate the collective T&D deferral benefit of both grid-side and customer-side DG facilities based on DG penetration levels, without applying the restrictive physical assurance requirement, but using a methodology equivalent or analogous to the method employed by Itron in its SGIP Year 6 Impact Report.

12. The price elasticity adder presented in the Itron Framework should not be used in the RIM, TRC, or the Societal Tests because if DG resources are planned, we should not assume their addition will impact market prices.

13. The Commission should require the use of the E3 reliability adder in the avoided costs adopted in D.05-04-024, and updated in D.06-06-063 for system reliability impacts in the RIM, TRC, and Societal tests.

14. Energy Division should study whether the new methodology adopted in D.09-06-028 to assess peak load contributions of intermittent resources in the Resource Adequacy rulemaking affects the use of the E3 Reliability Adder in the DG cost-benefit tests.

15. If a DG customer or developer has an estimate of the reliability benefits of DG projects to DG customers, this information may be reported by program administrators, but should not be used in the cost-benefit tests.

16. Until further review by the Commission, cost-benefit models should not assume that DG projects improve employment or tax revenues in California.

17. Energy Division should ensure the entity performing the cost-benefit analyses performs a qualitative assessment of the market transformation effects of DG programs, based on the Itron or E3 method, or other reasonable substitute.

18. The consultant should first perform the SPM tests without any market transformation analysis, and then conduct a second set of the tests that incorporates a market transformation component, which includes an assessment of progress toward the goal of market transformation and how cost-benefit test results might change as DG technologies evolve.

19. Reduced transmission, distribution and non-fuel generation revenues should be included in RIM Tests based on estimates derived from utility rate tariffs and DG production data.

20. Current and most recent data from SGIP and CSI databases about the costs of installing, maintaining, and operating DG projects should be included in the TRC, Societal, and Participant Tests.

21. The Commission should apply the same method used for valuing environmental impacts of energy efficiency when valuing environmental impacts of DG in order to compare resource options with consistent avoided costs.

22. The Commission should use the method described in the Itron Framework, along with the most current avoided costs inputs used to evaluate energy efficiency, to value environmental impacts of DG.

23. The valuation of environmental impacts may require adjustments at a future date to account for the effects of a cap and trade regime to reduce GHG emissions.

24. The Participant, TRC and the Societal Tests for a DG cogeneration plant should estimate the plant's efficiency relative to central station facilities.

25. Exemptions from standby charges should be reflected as a cost in the RIM Test and a benefit in the Participant Test.

26. The costs and benefits of net metering should be included in the SPM cost-benefit tests.

27. Reduced CRS revenues should not be included as a cost in the RIM Test.

28. SGIP and CSI incentive payments should be included as a cost in the TRC, Societal, RIM, and PA Cost Tests, and as a benefit in the Participant, TRC, and Societal Tests.

29. Tax incentives should be included as a benefit in the Participant Test.

30. Federal tax incentives should be included as a benefit in the TRC and Societal Tests, and state tax incentives should be considered a transfer payment in both tests.

31. Attachment A, which summarizes costs and benefits and input variables for each of the adopted cost-benefit tests, should be adopted to guide cost-benefit calculations for DG facilities, subject to modification as the Commission determines.

32. The Energy Division should oversee the cost-benefit analysis work to ensure the consultant performing the cost-benefit analyses applies the cost-benefit models adopted in this decision and the most recent data available.

33. If data to perform the cost-benefit tests is not readily available or it is cost prohibitive to obtain it, Energy Division may direct the consultant performing the work to use alternative data sources, with accompanying justification.

34. The Commission should review the results of the cost-benefit tests adopted in this order as a tool to assist in DG program evaluation.

35. Once the cost-benefit analysis is completed, the ALJ shall allow parties to comment on the completed analysis and, in consultation with the Assigned Commissioner, consider hearings or workshops on further modifications and refinements to the analysis as deemed necessary.

O R D E R

IT IS ORDERED that:

1. The Commission's distributed generation programs, which are supported by incentives and rate exemptions funded by jurisdictional utility ratepayers, shall be analyzed using the three cost-benefit tests described in this decision, namely, the Participant Test, the Total Resource Cost Test (including its variant,

the Societal Test), and the Program Administrator Cost Test, and the tests shall be run with the input variables and data sources set forth in Attachment A.

2. Beginning on the effective date of this order, the Commission's Energy Division shall ensure the cost-benefit models set forth in Ordering Paragraph 1 and Attachment A are applied to distributed generation programs. If data to perform the tests as set forth in Attachment A is not readily available, or if it is cost-prohibitive to obtain it, Energy Division may use its discretion to direct the entity performing the analysis work to use alternative data sources, as long as any deviations are communicated and justified in the resulting study.

3. Within 30 days of this order, Energy Division shall initiate cost-effectiveness studies as described in the California Solar Initiative Program Evaluation Plan using the cost-benefit methodology adopted in Ordering Paragraph 1.

4. Within six months of this order, Energy Division shall ensure the Self-Generation Incentive Program program administrators have begun efforts to hire independent contractors to perform a cost-benefit analysis of the Self-Generation Incentive Program for all prior program years using the methodology adopted in Ordering Paragraph 1.

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, Southern California Gas Company, and the California Center for Sustainable Energy shall develop data collection capabilities and work with the Commission's Energy Division to obtain, facilitate the obtainment of, or provide the program data, distributed generation participant data or any other relevant information specified in Attachment A in order to apply the cost-benefit models adopted in this order.

6. The Energy Division should report to the Administrative Law Judge and assigned Commissioner whether modifications are necessary to the reliability assumptions for intermittent distributed generation resources used in the adopted cost-benefit tests.

7. Following completion of the cost-effectiveness analysis, the assigned Commissioner or Administrative Law Judge shall allow comments on the completed analysis, and may hold workshops or hearings as deemed necessary to consider refinements and modifications to the variables or data sources used in this cost-benefit methodology.

8. Rulemaking 08-03-008 remains open.

This order is effective today.

Dated August 20, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

ATTACHMENT B
STATUTORY DEFINITIONS OF DISTRIBUTED ENERGY RESOURCES AND SOLAR ENERGY SYSTEM

Public Utilities Code Section 379.6

(a) (1) The commission, in consultation with the State Energy Resources Conservation and Development Commission, shall administer, until January 1, 2012, the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000.

(2) Except as provided in paragraph (3), the extension of the program pursuant to Chapter 894 of the Statutes of 2003, as amended by Chapter 675 of the Statutes of 2004 and Chapter 22 of the Statutes of 2005, shall apply to all eligible technologies, as determined by the commission, until January 1, 2008.

(3) The commission shall administer solar technologies separately, after January 1, 2007, pursuant to the California Solar Initiative adopted by the commission in Decision 06-01-024.

(b) Commencing January 1, 2008, until January 1, 2012, eligibility for the program pursuant to paragraphs (1) and (2) of subdivision (a) shall be limited to fuel cells and wind distributed generation technologies that meet or exceed the emissions standards required under the distributed generation certification program requirements of Article 3 (commencing with **Section** 94200) of Subchapter 8 of Chapter 1 of Division 3 of Title 17 of the California **Code** of Regulations.

(c) Eligibility for the self-generation incentive program's level 3 incentive category shall be subject to the following conditions:

(1) Commencing January 1, 2007, all combustion-operated distributed generation projects using fossil fuel shall meet an oxides of nitrogen (NO x) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on
100 percent load.

(2) Combined heat and power units that meet the 60-percent efficiency standard may take a credit to meet the applicable NOx emissions standard of 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British thermal units (Btus) of heat recovered.

(3) Notwithstanding paragraph (1), a project that does not meet the applicable NOx emissions standard is eligible if it meets both of the following requirements:

(A) The project operates solely on waste gas. The commission shall require a customer that applies for an incentive pursuant to this paragraph to provide an affidavit or other form of proof, that specifies that the project shall be operated solely on waste gas. Incentives awarded pursuant to this paragraph shall be subject to refund and shall be refunded by the recipient to the extent the project does not operate on waste gas. As used in this paragraph, "waste gas" means natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

(B) The air quality management district or air pollution control district, in issuing a permit to operate the project, determines that operation of the project will produce an onsite net air emissions benefit, compared to permitted onsite emissions if the project does not operate. The commission shall require the customer to secure the permit prior to receiving incentives.

(d) In determining the eligibility for the self-generation incentive program, minimum system efficiency shall be determined either by calculating electrical and process heat efficiency as set forth in **Section** 218.5, or by calculating overall electrical efficiency.

(e) In administering the self-generation incentive program, the commission may adjust the amount of rebates, include other ultraclean and low-emission distributed generation technologies, as defined in **Section** 353.2, and evaluate other public policy interests, including, but not limited to, ratepayers, and energy efficiency and environmental interests.

(f) On or before November 1, 2008, the State Energy Resources Conservation and Development Commission, in consultation with the commission and the State Air Resources Board, shall evaluate the costs and benefits, including air pollution, efficiency, and transmission and distribution system improvements, of providing ratepayer subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation," as defined in **Section** 353.2, as part of the integrated energy policy report adopted pursuant to Chapter 4 (commencing with **Section** 25300) of Division 15 of the Public Resources **Code**. The State Energy Resources Conservation and Development Commission shall include recommendations for changes in the eligibility of technologies and fuels under the program, and whether the level of subsidy should be adjusted, after considering its conclusions on costs and benefits pursuant to this subdivision.

(g) (1) In administering the self-generation incentive program, the commission shall provide an additional incentive of 20 percent from existing program funds for the installation of eligible distributed generation resources from a California supplier.

(2) "California supplier" as used in this subdivision means any sole proprietorship, partnership, joint venture, corporation, or other business entity that manufactures eligible distributed generation resources in California and that meets either of the following criteria:

(A) The owners or policymaking officers are domiciled in California and the permanent principal office, or place of business from which the supplier's trade is directed or managed, is located in California.

(B) A business or corporation, including those owned by, or under common control of, a corporation, that meets all of the following criteria continuously during the five years prior to providing eligible distributed generation resources to a self-generation incentive program recipient:

(i) Owns and operates a manufacturing facility located in California that builds or manufactures eligible distributed generation resources.

(ii) Is licensed by the state to conduct business within the state.

(iii) Employs California residents for work within the state.

(3) For purposes of qualifying as a California supplier, a distribution or sales management office or facility does not qualify as a manufacturing facility.

Public Utilities Code Section 2852 (a)(3)

"Solar energy system" means a solar energy device that has the primary purpose of providing for the collection and distribution of solar energy for the generation of electricity, that produces at least one kilowatt, and produces not more than five megawatts, alternating current rated peak electricity, and that meets or exceeds the eligibility criteria established by the commission or the State Energy Resources Conservation and Development Commission.

(END OF ATTACHMENT B)