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SHAPING A CALIFORNIA DISTRIBUTED ENERGY RESOURCES PROCUREMENT

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DER Stakeholder Collaboration at Work: Shaping a California DER Procurement

**A Report of the
EPRI Distributed Energy Resources
Public/Private Partnership**

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DEDICATION

This report is dedicated to Joseph Iannucci, who delighted in this project, brought wisdom and infectious enthusiasm to the collaboration, and called it a leading effort in the nation being watched by other states and the US Department of Energy, whom Joe represented. The project was privileged to have Joe be part of the collaborative and sorely misses his quips and insights, which we will carry forward through all of our days.

CONTENTS

- 1 INTRODUCTION 1-1**
 - EPRI DER Public/Private Partnership 1-1
 - Previous DER Market Integration Reports 1-1
 - DER Scoping Study, Spring 2003 1-1
 - Framework for Developing Collaborative DER Programs, Fall 2003 1-2

- 2 CALIFORNIA DISTRIBUTED ENERGY RESOURCES PILOT PROJECT 2-1**
 - Background 2-1
 - SCE’s Proposed DG Solicitation 2-2
 - Approach and Scope of Support for SCE Pilot Procurement 2-4

- 3 ORGANIZING THE COLLABORATIVE 3-1**
 - Selecting Participants 3-1
 - Ensuring Fairness and Openness 3-2
 - Overview of the Work 3-3

- 4 BRINGING STAKEHOLDERS TOGETHER AND DEFINING THE ISSUES 4-1**
 - Workshop Preparation 4-1
 - Specificity of System Information 4-1
 - Screening for Potential DER Projects 4-2
 - Analyzing Costs and Benefits from Multiple Stakeholder Perspectives 4-2
 - Workshop Objectives, Topics and Presentations 4-3
 - Workshop Participation 4-3
 - Workshop Results 4-4

- 5 COLLABORATING TO RECOMMEND SOLUTIONS 5-1**
 - Issue Group Process 5-1
 - Priority Issues Addressed 5-1
 - Post-Workshop Activity 5-2

| | |
|--|------------|
| 6 RECOVERING STAKEHOLDERS TO INTEGRATE THE WORK..... | 6-1 |
| The Second Workshop..... | 6-1 |
| Evaluating the Process – What Worked Well and What Can Be Improved | 6-2 |
| What Worked Well..... | 6-2 |
| What Could Be Improved | 6-3 |
| Identifying Next Steps | 6-3 |
| | |
| 7 ACHIEVEMENTS, FINDINGS & RECOMMENDATIONS FROM THE CALIFORNIA PILOT PROJECT | 7-1 |
| Achievements of California’s DER Collaborative Toward a Successful DG Solicitation | 7-1 |
| <i>Framework</i> -Recommended Initiatives Addressed in This Pilot..... | 7-3 |
| Lessons for Moving Forward with DER Market Integration..... | 7-5 |
| Specific Ideas for Future Consideration | 7-8 |
| | |
| A CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP PARTICIPANTS..... | A-1 |
| | |
| B CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP PRESENTATIONS | B-1 |
| | |
| C CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP ATTENDEES..... | C-1 |
| | |
| D CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP SUMMARY REPORT | D-1 |
| Introduction | D-1 |
| Purpose | D-1 |
| Attendees | D-1 |
| Major Outcomes..... | D-1 |
| Workshop Approach..... | D-2 |
| Issue Groups..... | D-3 |
| | |
| E CALIFORNIA DER PILOT PROGRAM – SOUTHERN CALIFORNIA EDISON REVISED DRAFT MODEL DEMAND LIMITATION AGREEMENT | E-1 |
| | |
| F CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP ATTENDEES | F-1 |
| | |
| G CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP SUMMARY REPORT | G-1 |
| Stakeholder Working Group Report | G-2 |
| SCE’s Plan for Integrating Customer-Operated DG into Distribution Planning | G-4 |

The Unresolved Issue: Self-Generation Incentive Program (SGIP) Eligibility G-6
What Worked, What Didn't, What's Missing G-6

**H CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP
PRESENTATIONS H-1**

LIST OF FIGURES

Figure 3-1 Project Timeline3-3

LIST OF TABLES

| | |
|---|-----|
| Table 2-1 SCE Pilot Compared with New York PSC Pilot | 2-4 |
| Table 5-1 Working Group Issues | 5-2 |
| Table 7-1 Collaborative Achievements | 7-2 |
| Table 7-2 Framework Initiatives Addressed by California Pilot Project | 7-4 |

1

INTRODUCTION

EPRI DER Public/Private Partnership

The Electricity Innovation Institute (E2I), a non-profit affiliate of EPRI, was chartered in 2001 to conduct strategic research and development through public/private partnerships. E2I initiated the Distributed Energy Resources (DER) Public/Private Partnership in 2002 to reduce barriers to DER deployment and to enable widespread DER integration where it brings value to the electricity enterprise. In 2005, EPRI assumed E2I's charter and programs to streamline the business and to reduce costs. Throughout this report, the DER Partnership will be referred as the EPRI DER Partnership. E2I will be referred to in historical context.

The Partnership comprises two platforms: DER Market Integration, to address market barriers to DER, and DER Environmental Benefits/Impacts, to conduct objective analysis of the environmental impacts of widespread DER. As described below, this report is the third in a series developed under the DER Market Integration platform.

The EPRI DER Partnership defines DER as small (usually less than 10 MW) energy generation, storage, or demand-side resources located near the load they serve. Generation technologies may include small gas turbines, microturbines, reciprocating engines, fuel cells, or photovoltaics, operated for stand-alone generation or combined heat and power (CHP) applications, and using either conventional fuels (e.g., natural gas or oil) or renewable resources (e.g., biogas, biomass, or solar radiation). DER storage may include flywheels, thermal storage, and other local storage technologies. DER may also include technologies and operations used for demand response or otherwise to reduce end-user load.

Previous DER Market Integration Reports

DER Scoping Study, Spring 2003

In January 2003, E2I assembled a group of DER stakeholders to identify gaps in research needed to encourage DER where it can add value to the electric system. The group assigned high research priority to DER market integration – defined to mean the development of win-win business models, regulatory approaches and utility rate structures that encourage DER that adds value to the system.¹ The group also recommended further scoping to refine the research agenda.

¹ In EPRI's DER Market Integration work, a 'win-win' approach is one that benefits multiple stakeholders without significantly harming others.

During April and May of 2003, the project team conducted a scoping study² to baseline the current market situation in key states, identify elements of win-win approaches, and recommend research actions to advance widespread DER integration. Team members interviewed twenty-seven stakeholders (including utilities and their affiliates, regulators, and DER equipment suppliers and project developers) actively involved with DER issues, and analyzed DER regulatory developments in New York, California and New Jersey. The team proposed win-win business elements for DER, and identified related research actions.

On May 30, 2003, these were presented to the project working group of DER stakeholders, consisting of thirty top thought leaders representing all segments of the DER community, at a workshop at EPRI headquarters in Palo Alto, California. The group reviewed the scoping study results, proposed a set of objectives to enable value-driven DER market integration, and prioritized the following action recommendations for the DER Partnership:

- Develop a catalog of actions that utilities and regulators can take to incentivize DER that adds value to the electricity enterprise;
- Examine DER costs and benefits, and how utility rate structures and incentive approaches can allocate them across stakeholder groups to achieve win-win outcomes; and
- Develop a framework for flexible, collaborative programs to refine and improve existing incentive approaches and implement new ones in several states.

Framework for Developing Collaborative DER Programs, Fall 2003

During the fall of 2003, the DER Partnership's Market Integration platform implemented the three action recommendations above that resulted from the DER Scoping Study.³

Addressing the first recommendation, the project team researched actions that some leading states and utilities have already taken to facilitate DER (often demand response) that adds value for electric systems and their customers. As part of a final *Framework* report, this work yielded a catalog of approaches reflecting the differing interests of distribution utilities, bulk power utilities, DER customers, and society at large. The catalog offers insights about what has been tried to date, as well as ideas and recommendations for designing the kind of win-win incentives favored by DER Partnership participants.

Accompanying the catalog in the *Framework* report is a discussion of utility revenue-setting and rate design methods available to allocate DER costs and benefits among stakeholders, and thus shape incentives that help or hinder DER integration. That discussion describes basic rate forms that can make it easier or harder to align stakeholder interests (such as volumetric charges, fixed charges, demand charges, and two-part rates). It also reviews options such as customer-oriented

² *Integrating Distributed Energy Resources into Emerging Electricity Markets: Scoping Study: Report of the E2I Distributed Energy Resources Public/Private Partnership*. E2I, Palo Alto, CA. 2004. 1011030.

³ This work was sponsored by the California Energy Commission, the New York State Energy Research and Development Authority, the Tennessee Valley Authority, City Public Service of San Antonio, and the Massachusetts Technology Collaborative. It is reported in *A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders ("Framework")*. E2I, Palo Alto, CA, 2004. 1011026.

demand subscription and non-firm standby rates, monetization of societal emissions costs, recognition of generation multipliers, and revenue-based PBR.

Addressing the second action recommendation of the DER Partnership, the project team identified and described costs and benefits that accrue to each stakeholder group (DER customer, utility shareholders and other ratepayers, and society at large). The team developed a spreadsheet model to quantify those costs and benefits from each stakeholder's perspective, and to illustrate how they can be reallocated among stakeholders to achieve win-win outcomes. The model structure enables users to vary numerous inputs relevant to DER projects to see how they affect the costs and benefits flowing to each stakeholder group. Its output reveals which stakeholders profit and which ones pay for different combinations of DER technologies under differing assumptions concerning energy prices, T&D deferral, 'generation multiplier' effects, emissions profiles, financing terms, operational characteristics, available incentives, etc.

The DER Partnership's third action recommendation was to initiate flexible, collaborative pilot programs in several states to refine and improve existing incentive approaches and implement new ones. To begin that process, the project team developed a framework to support such programs.

The framework builds on the catalog of approaches, rate design options, cost/benefit descriptions and modeling tool to outline a four-part process for collaboration among willing stakeholders to develop innovative DER pilot programs. The process begins by structuring the collaborative and defining the program's scope and objectives. It then introduces basic strategies for participants to consider in developing programs, and outlines the stakeholder needs that each strategy can address. Thirdly, it considers options available to tailor each basic strategy to local conditions. Finally, the framework offers a detailed example showing how the catalog, incentive mechanisms, and cost/benefit modeling tool can be combined to evaluate a potential CHP pilot project, or to shape other collaborative DER programs.

The *Framework* report identified a wide variety of collaborative initiatives that could help integrate DER into larger electricity markets – ranging from specific methods of leveraging DER values, introducing efficient incentives, and eliminating barriers, to rate design changes and high-level policy approaches. At the same time, however, it emphasized that any pilot program would need to tailor its objectives to meet particular state, regional and local needs through the stakeholders' collaborative process. The Southern California Edison DER pilot project described next provides a real-world example of that process.

2

CALIFORNIA DISTRIBUTED ENERGY RESOURCES PILOT PROJECT

Background

Southern California Edison (SCE) is one of the nation's largest investor-owned electric utilities, serving over 50,000 square miles of service territory in Central and Southern California. On an average day, it provides power for about 13 million people, 430 cities and communities, 5,000 large businesses and 280,000 small businesses. To do this, SCE relies on nearly 5,000 transmission and distribution circuits, more than 400 transmission and distribution crews, and over 13,000 employees.

SCE is regulated by the California Public Utilities Commission (CPUC). Since the mid-1990s, the CPUC has taken an active regulatory interest in DER. Beginning in 1998, the CPUC and the California Energy Commission initiated extensive rulemakings focused specifically on distributed generation or 'DG' (as distinct from demand-side resources or demand response). These proceedings involved numerous stakeholders representing all sectors of the DG community, including utilities, state agencies, municipalities, environmental and consumer advocates, and DG equipment vendors and project developers.

The proceedings resulted in a February 2003 CPUC decision and Order⁴ that addressed a wide range of issues which the parties had identified, supported through written and oral testimony, and briefed extensively over many months. Among other things, the 2003 Order required California's investor-owned utilities, including SCE, to (1) incorporate in their distribution planning processes a utility-proposed DG procurement process to evaluate alternatives to distribution system upgrades, and (2) develop model contracts for DG designed to defer such upgrades.⁵

The CPUC's 2003 decision imposed two important conditions for utility DG procurements:

- **'Physical Assurance'**. The rulemaking had focused on DG that could avoid or defer utility distribution upgrades.⁶ To be considered for that purpose, DG installations would need to

⁴ CPUC Decision 03-02-068 in R.99-10-025, February 27, 2003.

⁵ Id., Ordering paragraphs 1-3, p. 72. On May 13, 2003 the utilities made compliance filings in the same proceeding, describing how they would incorporate DG in their planning and procurement, and proposing model contracts as a starting point for negotiations with DG providers selected through this process.

⁶ California DG rulemakings began in 1998-99, when the state's utilities were required to divest most of their generation, and expected to become wires-only utilities. That, and the structure of California's wholesale markets at the time, may explain the rulemaking's focus on DG primarily as an alternative to distribution capacity expansion. E21's 2003 Scoping Study noted that

provide devices and equipment to *physically assure* that customer load equal to the DG unit's capacity would be interrupted if the DG did not perform as contracted, to prevent harm to the distribution system and other customers.⁷

- **Deferral Value.** Utility payments to distributed generators selected to defer wires investments cannot exceed a prescribed formula: the utility's short-term carrying cost of capital, multiplied by the cost of the planned distribution addition and the number of years of deferral.⁸

The CPUC's 2003 decision contemplated a DG procurement process based on a utility-issued request for proposals (RFP). Utility RFPs were expected to incorporate model contracts similar to those the utilities had submitted to the CPUC in May 2003 – with little or no input from other DG stakeholders who the utilities and the Commission hoped would respond with DG projects meeting utility needs.

SCE's Proposed DG Solicitation

SCE had been actively involved as a stakeholder in the earlier Scoping Study. It had also participated in the DER Partnership 2003 work to develop the *Framework* for collaborative DER pilot projects. As a result, SCE representatives believed that the DER Partnership's collaborative approach could help the utility design a planning and procurement process that would meet CPUC requirements and yield DG projects that could defer distribution investment.

SCE was also aware that New York's pilot program to integrate DG into utility planning and procurement through an RFP process had been under way for several years, but its early solicitations had not elicited strong interest from DG providers, or resulted in successful projects. Industry feedback suggested that utility solicitations could benefit from a better understanding of the needs of prospective DG providers, and that providers could be more responsive if they learned more about utility system planning processes and constraints. Believing that a more collaborative approach might meet these needs, SCE agreed in the spring of 2004 to work with the DER Partnership project team and stakeholders toward those ends.

SCE's original objective was to issue its first DG solicitation implementing the CPUC directives by November 2004. The utility initially hoped to target projects that could be installed and operational in time to meet peak distribution system needs about 18 months later (in the summer of 2006). Early discussions concluded that 24 to 36 months would be a more realistic target, in part because completion of any DG project would need to be assured in time for SCE to revert to its traditional wires solution if that became necessary.

Based on its normal distribution planning process, SCE expected to be able to identify three to five distribution planning areas facing significant upgrade investments that might be deferrable

states with different restructuring regimes and wholesale market structures have taken a broader view of DER's contribution to the larger electricity enterprise. California has also moved toward that view in a 2004 DER rulemaking (R.04-03-017).

⁷ Id., Finding of Fact 7, p. 69; Conclusion of Law 3, p. 70; note 2, p.7; and discussion at pp. 12-13.

⁸ Id., Conclusion of Law 6, p. 71, and Ordering paragraph 4, pp. 72-73.

using DG – provided it was the right size, in the right location, installed at the right time, and with physical assurance to guarantee the load reduction needed to defer capacity upgrades.⁹

In the fall of each year, SCE’s annual planning update identifies distribution upgrades needed within the next two years, based on information and projections that evolve during that planning year. Work on this DG pilot project began in the spring of 2004, so SCE had not yet settled on specific circuits or distribution upgrades that it would require in 2006-07, when DG projects solicited in the fall would need to be operational.

From past experience, the utility expected to identify three to five local areas on its system where DG had the potential to defer specific distribution investments. The amount of new capacity required in each area of course would vary with the condition of the distribution infrastructure, its forecasted load growth, and other factors. In general, however, SCE expected that capacity additions needed in each area would be in the multi-megawatt range, perhaps averaging three to five MW per area. Multiplying the estimated number of areas by the average MW likely to be needed in each one, this initial pilot procurement was expected to target about 10 to 25 MW of DG-provided capacity deferral, once SCE determined its actual distribution system needs later in the year.

For this DER pilot to meet SCE’s proposed schedule, the stakeholder collaboration needed to begin around June and be completed by October 2004. This relatively short period, coupled with SCE’s need to comply with the CPUC’s boundary conditions for DG solicitations, dictated the scope of the pilot. The following table compares its scope with that of the New York pilot program.¹⁰

⁹ These four criteria were identified by the CPUC as necessary to support distribution deferral payments to DG providers. See D.03-02-068 in R.99-10-025, February 27, 2003; at pp. 16-17 and p. 45.

¹⁰ Table 7-2 on p. 7-4 below compares the SCE pilot activities to date with the universe of potential DER integration initiatives identified in E2I’s 2003 *Framework*.

**Table 2-1
SCE Pilot Compared with New York PSC Pilot**

| Program Characteristic | New York | California (SCE) |
|---|---|---|
| Regulatory context | NY PSC established pilot program requirements, including procurement mechanism, number of solicitations, timelines, cost thresholds for RFPs, project evaluation criteria, etc. | CPUC required utilities to consider DG in planning, procure it if competitive, & develop model contract terms. CPUC set ceiling price formula and required physical assurance for distribution deferral. Utilities are otherwise free to structure their own solicitations. |
| Duration of pilot | 3 years | 6 months (collaborative RFP design only) |
| Number of utilities | 6 | 1 |
| Number of solicitations planned, in total | 2 each year for each utility; 2 additional for Con Ed in third year; total of 38 | 1 |
| Number of solicitations issued to date | at least 12 | 1 in progress, to be issued in early 2005 |
| Solicitation type | RFP | RFP |
| Solicitation design | PSC and utilities | SCE, with collaborative input from other stakeholders |
| Model contract(s) | developed by NY utilities | Yes |
| Model contract design | developed by NY utilities | initially by SCE, substantially modified through collaboration |

Approach and Scope of Support for SCE Pilot Procurement

SCE’s planning and procurement needs presented an early opportunity to test the DER Partnership’s collaborative approach, apply the tools developed through the 2003 Market Integration work, and begin to implement some of its findings and recommendations.

The intent of the project was to support SCE’s objectives of designing a DG procurement process consistent with CPUC directives that would meet specific distribution area needs, and would encourage successful third-party proposals to integrate DG into SCE’s system.¹¹ SCE’s aims for the process were similar: to develop a solicitation that would be easy to understand and respond to; encourage many proposers to submit innovative options for the utility; and result in sound proposals that SCE ratepayers could enthusiastically support.¹²

¹¹ The CPUC’s 2003 decision did not restrict utility ownership or operation of DG. The Commission stated that utilities and their affiliates remain free to enter customer-side DG markets along with independent third parties, although they ‘do not appear to offer any sort of specialized expertise in the manufacture, sale, or operation of distributed generation on the customer side of the meter, so we do not encourage them to enter this new business line within the regulated utility’. (D.03-02-068 in R.99-10-025, February 27, 2003; at p. 23.) In any case, SCE indicated from the outset that this initial procurement would focus on customer-sited, customer- or third-party owned DG, and that the utility and its affiliates did not intend to submit proposals.

¹² Remarks of SCE Vice-President Jim Kelly welcoming participants to the first of two collaborative workshops hosted by SCE and E2I; July 14, 2004.

Specific goals of the SCE pilot program included:

- Using a stakeholder collaborative process to develop a DG or DER solicitation that developers, customers, vendors, and other third parties will confidently bid on, and that will lead to a pilot that can serve as a model for other procurements
- Testing and demonstrating the stakeholder collaborative process
- Developing innovative win-win approaches for encouraging DER and advancing DER market integration and policy
- Documenting lessons learned and win-win approaches developed from the stakeholder collaboration so they can be duplicated and scaled in California and other states.

To help achieve these goals, the DER Partnership project team agreed to help SCE in the following tasks:

1. Recruiting participants and organizing the collaboration
2. Supporting SCE's analysis of distribution system needs, and conducting preliminary analyses of costs and benefits to key stakeholder groups
3. Planning and preparing materials for an initial stakeholder workshop
4. Facilitating initial collaborative discussions at the opening workshop
5. Leading stakeholder groups in developing win-win approaches for a successful pilot
6. Reconvening stakeholders in a second workshop to integrate results into a successful solicitation
7. Supporting SCE in developing its DG RFP
8. Monitoring results, developing lessons learned, and reporting on what was done

These activities took place from May through early October, 2004. As noted later, changes in SCE's distribution planning cycle, and its desire to seek CPUC approval for improvements to its Model DG Agreement resulting from the collaborative's work, caused SCE to postpone the target date for its DG solicitation from November 2004 to March 2005, and for execution of DG contracts to October, 2005. Final results of the California DER collaborative pilot will not be known before then, but the next chapters highlight some of the challenges and successes of the collaborative stakeholder activities that have now been completed.

3

ORGANIZING THE COLLABORATIVE

The 2003 *DER Framework* report posited that DER stakeholders' underlying interests are often more compatible than the positions they advocate in formal regulatory proceedings that address DER issues. In those forums the parties' positions, advocated by legal counsel, often proceed from incomplete understanding of other parties' needs, desires and business constraints, without the more nuanced appreciation that comes from informal give-and-take among principals. Regulatory litigation generally is designed to yield a decision that parties can act on (or challenge, as the case may be) – not to produce consensus or compromise, or to build relationships among businesses that have much to gain from each other, but operate in very different environments.

The Framework's collaborative approach, by contrast, is intended to help structure non-adversarial exchange of ideas and constructive cooperation among stakeholders, to find solutions that benefit as many as possible, as much as possible, with as little prejudice to others as possible. The Framework suggested that this works best when care is taken to organize and structure the collaborative from the outset.

Selecting Participants

The DER Partnership assumed primary responsibility for structuring the collaborative, including identifying and selecting the participants. The challenge here was to balance potentially conflicting needs. On the one hand, it was important to accommodate as many interested stakeholders as possible, to ensure a wide range of knowledge, experience and viewpoints that could contribute to innovative solutions. On the other hand, it was essential to limit the group to a size and composition that could meet regularly and with continuity over several months; could focus in depth on a variety of complex issues; was motivated by a genuine interest in the outcome; and could be organized, managed and coordinated effectively.

The solution was to create a dual structure for the collaborative. This consisted of a relatively small core group (the 'working group') responsible for the Collaborative's day-to-day work, and a larger group that also included advisory members with strong DER experience and/or valuable institutional perspectives, but without a direct stake in the SCE solicitation (i.e., not in a position to respond with actual DG resources or projects). The larger group brought a broader outlook, and acted as a sounding board for the working group's more concentrated work. The DER Partnership project team facilitated and directed the work of both groups.

Sixteen participants were initially invited to join the working group. They included representatives of five companies engaged in DER project development; five DG equipment manufacturers

or vendors; two customer groups or associations; and four SCE personnel responsible for distributed generation, transmission and distribution engineering, and customer service.

The larger group, most of which sent representatives to one or both California DER pilot project workshops, included all working group members; representatives of the California Energy Commission and Public Utilities Commission, NYSERDA, the Massachusetts Technology Collaborative, and the U.S. Department of Energy; and interested personnel from other utilities including CPS San Antonio, Southern California Gas, San Diego Gas & Electric, NStar Electric & Gas, and First Energy.¹³

Ensuring Fairness and Openness

The collaborative's overall objective was to enlist the broader DG community to help SCE develop a competitive solicitation process that would yield viable proposals for projects that could defer SCE distribution investments. SCE chose to target the solicitation to its customers who could act as site hosts, working with third-party DG providers if they elected to do so.

In selecting collaborative participants, the DER Partnership considered both customers and DG providers. With respect to *customers*, SCE had not yet identified the distribution areas its solicitation would target, and could not provide customer names in those areas (even apart from questions of customer confidentiality). Rather than invite some individual SCE customers and exclude others, the project team chose to invite representatives of customer groups that could present general customer perspectives, but would not gain any advantage for individual customers who might later propose DG solutions.

With respect to *DG providers*, the project team made every effort to identify potential provider representatives that could convey not only their own companies' views, but the views of other similar companies in the industry. The California DER pilot project needed to engage companies willing to commit time and resources to the collaboration, and it needed to limit the working group to a manageable and productive size. This meant that some but not all potential DG providers would participate in the collaborative, and that it was important to structure a process that would not prejudice others who might later wish to respond to SCE's solicitation.

The DER Partnership project team proposed a set of guidelines designed to balance the need for an efficient and productive collaborative process, with the need for fairness and integrity in SCE's solicitation process. The guidelines, accepted by SCE and followed in the Collaborative, provided for:

- Posting on E2I's public website¹⁴ information about the collaborative process, workshop attendance and presentations, and a report on workshop activities, all available for download
- Objective criteria for other interested parties to join the collaborative as it proceeded

¹³ See Appendix A for the names and affiliations of working group members, advisors and the project team.

¹⁴ http://www.e2i.org/e2i/extra/California_DER_Pilot_Project.html

looking work on the conceptual design of an SCE ‘circuit of the future’ which will showcase cutting-edge technologies for DG, energy efficiency, demand response, and advanced communications and controls. SCE’s team also included representatives from Customer Service, Distribution Engineering, Regulatory Affairs and the utility’s General Counsel.

4

BRINGING STAKEHOLDERS TOGETHER AND DEFINING THE ISSUES

Workshop Preparation

As collaborative participants were being identified and guidelines for a fair and open process developed, the project team worked with SCE to plan and prepare for the opening stakeholder workshop.

This first workshop was intended to help non-utility stakeholders (DG providers, customer representatives and others) understand more about how SCE does its distribution planning; how it will value potential DER offerings; and how regulators will assess their costs and benefits for other utility customers, shareholders and the general public. The workshop was equally intended to help SCE personnel, accustomed to operating in a regulated environment, understand how non-regulated DG vendors, project developers and utility customers would evaluate the costs, risks and benefits of responding to an SCE solicitation, and what could smooth the procurement path for both SCE and prospective respondents.

Specificity of System Information

The DER Partnership project team believed that the more concrete and specific the system information SCE provided, the more useful it would be to DG providers who needed to understand how their projects could support SCE's system, and what value they might offer to the utility. The challenges were to balance these considerations against utility concerns over disclosing sensitive business information and against concerns over fairness to other potential bidders not participating in the Collaborative, and not privy to such information in advance of the solicitation.

SCE's internal analysis would identify areas where the utility anticipates a need for distribution upgrades or expansion (usually due to population and business growth). The utility was expected to identify and rank perhaps three to five distribution planning areas where it would need relief over its two- to three-year planning horizon. However, during discussions in the spring, SCE explained that its normal planning process would not actually identify specific distribution circuits or construction projects needed until the fall, based partly on actual load growth and operating experience over the summer. The fact that data specific to projects that would be part of the solicitation was unavailable in any case, mooted concerns over revealing such information to potential bidders who were part of the Collaborative, but not to others.

Reflecting its planning realities and business concerns, SCE proposed to present historical data from its 2003 planning cycle, but without identifying specific planning areas, distribution circuits or construction projects represented by the data. This data was intended to be representative of typical SCE distribution expansion projects, but not necessarily identical to the forward-looking data for different parts of its distribution system that SCE would compile later in 2004, and that would drive its DG solicitation.

Screening for Potential DER Projects

Before the first stakeholder workshop, E2I's project team worked with SCE's DER planners and engineering professionals to understand the process and analysis SCE uses to estimate local DER values, and described processes that other utilities had used to integrate DER into their distribution planning. The team also provided SCE with an Excel spreadsheet template for high-level DER technical and economic screening, to help planners identify key issues that make DER either more or less attractive in different areas. SCE compared this tool with screening tools developed in-house and incorporated parts of it that augmented its own capabilities.

Analyzing Costs and Benefits from Multiple Stakeholder Perspectives

In parallel with this work, the project team used the modeling tool developed for its 2003 *Framework* report to develop a preliminary cost and benefit analysis of DER projects from the perspective of multiple stakeholders invited to participate in the SCE Collaborative. This analysis would be presented at the first workshop to illuminate each stakeholder group's economic perspective, in order to facilitate DER projects that could succeed from all perspectives – i.e., to identify potential 'win-win-win' opportunities.

To do that, the team updated the 2003 cost-benefit modeling tool with the most current set of inputs, and defined the ranges of critical uncertainties. Core inputs confirmed or updated included SCE rates, system energy and capacity values, and DER cost and performance. Collaborative participants later commented on input assumptions based on their own expertise and experience. Once updated, the tool would be used to help identify the highest value DER applications – those most likely to result in 'win-win-win' outcomes – for discussion at the first workshop.

Taken together, the purpose of the activities described above was to improve workshop participants' understanding of –

- The nature and magnitude of DER's potential value for the local utility system;
- The requirements DER must meet to provide that value;
- The most promising types of applications from a cost-benefit perspective; and
- The methods described in the Framework to use this information to craft approaches that meet the needs of as many stakeholders as possible.

These were the major activities completed as background for the first stakeholder workshop. Their results were presented at the workshop along with other topics listed in the next section.

Workshop Objectives, Topics and Presentations

SCE and the DER Partnership hosted the first stakeholder workshop on July 14-15, 2004, at SCE's Customer Technology Application Center (CTAC) in Irwindale, California (east of Pasadena). The workshop's objectives were:

- To increase understanding and develop trust among stakeholders for productive collaboration
- To introduce the DER Partnership cost-benefit tool and Framework
- To identify win-win-win approaches with the highest potential for success in this pilot
- To form smaller working groups to address priority issues and develop recommendations

The agenda topics for the first day of the July workshop are shown below. Appendix B includes contains a link to available presentations and other materials for each topic.

- DER Partnership Collaborative Approach for Win-Win DER Opportunities
- SCE's Distribution Planning Process Valuing DG as a Distribution Alternative (examples from SCE 2003 sample projects)
 - Computing DG value
 - analyzing costs & benefits for multiple stakeholders
- Key Elements of SCE's Proposed RFP, Fall 2004
- Stakeholders' Interests, Needs and Issues
- DER Partnership Collaborative Strategies and Program Examples
- Breakout sessions to prioritize top issues emerging from workshop sessions
- Reconvene and assign group priorities for issues meriting in-depth attention

Following the stakeholders' prioritization of issues at the end of the workshop's first day, the project team organized and grouped the highest priority issues. On the second day, July 15, the team offered a strawman for assigning sets of issues to smaller working groups. Attendees fine-tuned the assignments and established two smaller 'Issue Groups', each facilitated by a member of the project team, to systematically address the stakeholders' priority concerns over the summer. The issues assigned to each group are described, and their outcomes reported, in Chapter 5.

Workshop Participation

Thirty-one people, including top officers and managers of their organizations, attended all or part of the July 14-15 stakeholder workshop.¹⁶ These included representatives of –

- Five DER project development companies
- Four DG equipment manufacturers and vendors

¹⁶ Appendix C lists the attendees at the July 14-15 Workshop.

- Four electric and/or gas utilities or affiliates, including SCE
- One public customer with multiple facilities in SCE's service area
- Two regulatory agencies, including the California Energy Commission and the Massachusetts Division of Energy Resources
- The U.S. Department of Energy
- E2I and EPRI program managers, and members of the project team

Workshop participants expressed considerable interest in all of the topics presented. They engaged actively and enthusiastically in the discussions on both days, and contributed helpful and important insights into the perspectives their organizations brought to the table. During the first workshop, and continuing through the summer's Issue Group meetings and the second workshop in early October, participants did not hesitate to express their views candidly and respectfully. Throughout the process, many expressed increasing trust and confidence in other stakeholders' willingness to contribute, and to consider different points of view.

Workshop Results

The summary report on the July workshop is included as Appendix D. The following highlights its description of the major outcomes of the workshop.

- SCE demonstrated its commitment to develop an RFP that attracts bidders and results in successful bids for solutions that make sense for all of its customers. Senior managers, engineers and project personnel from several of the utility's business units echoed this.
- Other stakeholders were also committed to helping SCE achieve a successful RFP. Even participants who were skeptical at first committed to work on the group's priority issues, and to make recommendations for SCE to consider in developing its solicitation.
- Major issues of concern to stakeholders included the following (explored further by the two Issue Groups over the summer):

'Physical assurance' – interpretation of the CPUC's requirement to interrupt a customer's normal load when its DG unit does not perform as contracted.

Distribution deferral value – Defined by the CPUC as the utility's short-term carrying cost of capital, multiplied by the cost of the planned distribution addition and the number of years of deferral. This is the ceiling price the utility can pay to DER providers, which by itself will rarely be enough to fully support customer-sited projects.

Self-Generation Incentive Program (SGIP) eligibility – California's current SGIP rules exclude customers who have entered into contracts with a utility to provide distribution-related DG services (e.g., capacity deferral) from eligibility for the utilities' self-generation incentive rebate. Where available, that rebate will likely exceed any distribution deferral payment the utility can offer, so the exclusion discourages DG deferral proposals (at least for units below 1.5 MW, the cutoff for SGIP incentives).

- The stakeholders raised other possibilities to help integrate DG, to be explored further by the Issue Groups. These included:

a more central role for utilities in integrating DG, including DG ownership
utility help in matching qualified developers with eligible customers
combining demand response with DG resources for distribution deferral

- The highest priority issues identified by workshop participants were categorized and assigned to two Issue Groups. The first group would focus on business models and regulatory issues, and the second on structuring the RFP process and documentation.

5

COLLABORATING TO RECOMMEND SOLUTIONS

Issue Group Process

The DER Partnership designed the workshop process to identify issues that were important to both the DG development community and SCE. On the second day of the July Workshop, representatives of each elected to join one of the two Issue Groups formed to work on high priority issues between the July and October workshops, and to find mutually acceptable approaches that could benefit multiple stakeholders.

Priority Issues Addressed

In looking at the list of priority issues identified during the workshop, it became clear that some pertained directly to the specifics of SCE's planned solicitation. Others pertained to longer-term barriers to widespread deployment of DG and DER. This second set of issues required a different approach than the first, and the involvement of some stakeholders not present in this Collaborative. A third set of issues included ones that would directly impact the RFP, but whose solution could not be negotiated within the Collaborative. Workshop participants decided to assign the issues that were longer-term or less amenable to collaborative influence to one Issue Group, and the RFP-specific issues to a second Issue Group. Each participant then selected the set of issues and the group he or she would be willing to work on between workshops.

For Issue Group 1, an example of a longer-term issue would be how to provide appropriate incentives for utilities to embrace DER as part of the solution to grid reliability. An example of an RFP barrier that the Collaborative could not resolve by itself would be the disincentive created by California's current Self-Generation Incentive Program rules, described earlier.

Issue Group 2 was set up to address 'nuts and bolts' issues in structuring SCE's first DER procurement, including some that had hindered other efforts around the country to incorporate DER into utility distribution planning and procurement. This Group was tasked to evaluate the RFP process being developed by SCE and to suggest ways to simplify it and otherwise encourage maximum participation by the DG community. It was also tasked to review a Model Agreement that SCE had previously filed with the CPUC to use as a starting point for negotiations with successful proposers, and to give SCE feedback regarding viable contract approaches and language from the perspective of customers and third-party DG providers.

The following table lists specific issues considered by each of the Groups. The issues are numbered for convenient reference, but not necessarily in order of priority.

**Table 5-1
Working Group Issues**

| Issue Group 1 | |
|-------------------------------------|--|
| 1 | Eligibility for Incentives: Are proposers entitled to deferral incentives under this solicitation also eligible for Self-Generation program incentives? |
| 2 | Physical Assurance Requirement: Is 'physical assurance' required every hour of the year, or only during periods when SCE expects to call on the DG resource? |
| 3 | Eligible Resources: Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response? |
| 4 | Alternatives to the RFP Process: Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process? |
| 5 | Additional DG Values: Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response? |
| 6 | Business Model: What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise? |
| Issue Group 2 | |
| 7 | DG Deferral Value: Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG? |
| 8 | Simplification of the Process: How can the solicitation process and/or SCE's Model DG Agreement be simplified to reduce all parties' transactions costs? |
| 9 | Availability of Distribution System Data: What distribution system data will SCE provide to help customers and developers prepare DG proposals that meet its needs? |
| 10 | Tailoring SCE Deferral Agreement to DG Project Realities: Can deferral periods be extended to provide greater value? Can SCE's Model Agreement be improved to encourage proposals? |
| 11 | Facilitating Interaction between SCE Customers and DG Developers: How will SCE customers be notified & developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise? |
| Other Issues (not addressed) | |
| | Schedule more construction time for projects |
| | RFP evaluation criteria for project selection |

Post-Workshop Activity

Between the July and October workshops, each Issue Group held a series of conference call meetings facilitated by the project team. Collaborative participants researched the issues raised in the first workshop, discussed alternative approaches, and tested them with other colleagues not directly involved in this collaborative process. They then brought these issues, vetted within their organizations, back to the Groups and discussed potential solutions with other conference call participants. All workshop attendees were notified of these calls and invited to participate, but in practice most of the specific issue work was done by interested and committed members of the respective Issue Groups. The Groups' resolution of issues and/or recommendations to SCE or others in a position to act are highlighted below.

Issue 1: *Eligibility for Incentives. Are proposers entitled to deferral incentives under this solicitation also eligible for SGIP incentives?*

The answer was no, because existing SGIP rules disqualify customers receiving contract payments for distribution upgrades or replacement deferrals. Most Issue Group 1 members felt that the SGIP rules were arbitrary and not based on a true value analysis. They articulated that view in a document forwarded to the staff of the California Energy Commission for their consideration.

Issue Group 1 suggested restructuring the SGIP program to target incentives toward areas of the State where the distribution and/or transmission systems are stressed. It argued that targeting DG projects to these areas would yield California ratepayers a better return on the public's investment. This approach would provide different incentive levels throughout particular regions of the State, based on the value that a peak load reduction would bring to each of the generation, transmission and distribution systems involved. To the extent that individual self-generation projects could provide value to an area of the distribution grid over and above the region-wide average, SGIP customers should be eligible to receive payments for those services (such as contracted load response via DG or other strategies) that provide actual value to distribution utilities, as long as the incentives do not result in 'double-dipping' for the same benefit. The proposal was offered for consideration to a group responsible for evaluating SGIP program changes. Other active proceedings at the CPUC and CEC (DG/DER Rulemaking, Avoided Cost Rulemaking, etc.) could also materially impact utility RFPs soliciting DG/DER.

Issue 2: *Physical Assurance Requirement. Is 'physical assurance' required every hour of the year, or only during periods when SCE expects to call on the DG resource?*

Questions had been raised at the workshop concerning SCE's leeway to interpret the CPUC's Order requiring 'physical assurance' as a prerequisite for utility deferral payments. Issue Group members determined that the CPUC's decision gave SCE and other utilities the flexibility to define the meaning of physical assurance within the context of the customer contract that guaranteed demand reduction when required by the utility. Given this conclusion, the development of proposed contract language was transferred to Issue Group 2.

Issue 3: *Eligible Resources. Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response?*

The history of the CPUC proceedings that directed utilities to incorporate DG in their planning and procurement, and some of the Commission's language, initially led SCE to conceptualize the RFP as a procurement limited strictly to DG. Issue Group discussions revealed that the economics of these projects could often be improved by recognizing other sources of demand reduction at customer facilities along with the DG installation. The discussions also revealed that SCE's purposes would be served if customers reduced their onsite demand at critical times, whether they did that with onsite generation alone, or by combining DG with other demand response measures. SCE did need assurance that customers, who agreed to reduce their demand on the distribution grid when called on by the utility, would in fact do so. In exchange, they would be paid for this firm reduction based on the value of deferring SCE's investment. That said, Issue Group partici-

pants recognized that the CPUC's intent was to encourage DG deployment. The Group therefore agreed that SCE's RFP should recognize some amount of demand reduction offered by customers, as long as they installed DG sufficient to cover their facility's critical loads (as defined by the customer).

Issue 4: Alternatives to the RFP Process. Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process?

Issue Group members investigated the possibility of proposing a standard tariff or distribution credit that would be available to any customer who would agree to SCE's terms and conditions for demand reduction, physical assurance, minimum generation, etc. The Group found that the CPUC's 2003 decision had considered arguments for DG tariffs or localized incentives, and chose not to embrace those approaches outside of a broader investigation into their implications for other areas of ratemaking. Since then, the CPUC has initiated comprehensive proceedings on DER costs, benefits and other issues that could reach this issue of targeted distribution incentives. The Group concluded that any attempt to redirect CPUC efforts toward allowing a pilot approach here would likely delay SCE's effort to procure DER alternatives for its 2006-07 construction projects. However, the Group fully agreed on the importance of streamlining DER procurement using these or similar concepts, and urged that future DER Partnership collaborative activities take this on.

Issue 5: Additional DG Values. Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response?

With SCE's help, the Group determined that incentives under the utility's existing load curtailment and demand response programs were based on the value that demand reduction brought to the *generation* portion of customer rates, but they did not account for values conferred on the *distribution* component of rates. For example, lower electric rates due to reduced peak purchases resulting from curtailment programs, did not reflect the benefits of those reductions to the distribution system. Because SCE's current incentives reflect generation but not distribution savings, recognizing the latter would not amount to 'double-dipping'. The Issue Group concluded that customers participating in SCE's existing curtailment and demand response programs should also be permitted to participate in its DG solicitation, and should be paid for any distribution deferral benefits they provide.

Issue 6: Business Model. What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise?

Issue Group 1 members discussed various business models that could advance the deployment of DER/DG in California and other states. They agreed with views expressed by DG providers during the July workshop that it was time to reexamine the role that distribution utilities could and should play in deploying least-cost DER resources to enhance local grid reliability. A number of DG providers pointed out that distribution utilities remain the hub of the electricity enterprise; are well situated to identify customer DER opportunities and help deploy and service DER installations; and can advance DER integration through centralized purchasing and development

activities. Enhancing the role of utilities as facilitators and integrators was identified as an important topic for further work by DER Partnership collaboratives.

Issue 7: DG Deferral Value. Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG?

This was one of the more difficult issues addressed by Issue Group 2. SCE was concerned that giving out information about its avoided construction costs could involve the company in contentious proceedings at the CPUC, and could result in higher bids from customers than they might otherwise offer. DG providers, on the other hand, did not want to waste time or incur the considerable expense of responding to an RFP if there was little value to deferring utility expansion projects. After much discussion, SCE agreed to include a ‘market reference price’ in the RFP. This price will provide some indication of relative value for the projects being presented, but it will not necessarily reflect the utility’s avoided cost, and will not prevent SCE from accepting customer proposals above or below the reference price. Final prices (i.e., deferral payments) will be negotiated between successful proposers and SCE based on the overall project value to the utility (not to exceed the deferral value formula established in the CPUC’s 2003 Order).

Issue 8: Simplification of the Process. How can the solicitation process and/or SCE’s Model DG Agreement be simplified to reduce all parties’ transactions costs?

Issue Group 2 worked through the sequence and details of the solicitation process, as well as the terms of the Model DG Agreement SCE had submitted to the CPUC in 2003 but now believed could be improved and made more appealing to DG customers. Based largely on input from the Collaborative and its own DER staff, SCE recast the agreement from one that imposed strict requirements to guarantee DG equipment performance, to one that focused on the customer’s commitment not to exceed agreed load levels at critical times. The result was a simpler, more flexible and considerably less onerous Model Agreement, more sensitive to the business realities facing DG customers and developers, and more likely to encourage viable responses to SCE’s DG solicitation. A copy of the proposed agreement (not yet submitted for CPUC review at this writing) and related materials are included as Appendix E.

Issue 9: Availability of Distribution System Data. What system data will SCE provide to help customers and developers prepare DG proposals that meet its needs?

The challenge here was to strike a reasonable balance between SCE concerns over system security and disclosure of sensitive business information, on the one hand, and the needs of customers and other potential proposers for enough information to enable them to assess the feasibility and cost of projects they might propose, and the value they could expect to receive for them.

Issue Group 2 reconciled these interests by recommending a two-step process, which would first identify qualified respondents and require them to sign binding non-disclosure agreements, and then provide detailed system information only to those respondents. This information would include specific locations where projects could potentially defer SCE investment, by street map,

zip code, or other concrete description. It would also include the amount of load reduction or DG capacity needed for deferral in each area, including incremental amounts for different years when SCE's forecasts permit. And it would include the hours when SCE expects to need load reduction/DG capacity for each area, the number of hours per month, which hours of the day, and the maximum number of hours per year during which proposers must commit to reduce load.

Issue 10: Tailoring SCE Deferral Agreement to DG Project Realities. Can deferral periods be extended to provide greater value?

DG developers were interested in maximizing the value of deferral payments by extending contract terms over multiple years. SCE's planning experience has been that distribution upgrades and expansion projects can be accurately projected at most two to three years in advance of the need. Contract terms for DG deferral projects in SCE's territory are unlikely to exceed three years, and most will be based on two-year planning cycles. During Issue Group discussions, DG providers proposed that SCE offer a limited option to renew these contracts, including a right of first refusal for existing projects. SCE accepted this proposal, and proposed option language now appears in Section 4.3 of the Model Agreement in Appendix E.

Issue 11: Facilitating Interaction between SCE Customers and DG Developers. How will SCE customers be notified & developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise?

Developers and equipment vendors desire as much support as possible from SCE to connect them with SCE customers interested in hosting projects. SCE agreed to facilitate interactions by

- Encouraging customers in targeted deferral areas to participate in the RFP process.
- Sharing with prospective proposers contact information for customers who respond to the first phase of the RFP process and agree to be contacted
- Holding customer-vendor 'fairs' in or near the targeted deferral areas

6

RECOVERING STAKEHOLDERS TO INTEGRATE THE WORK

The Second Workshop

On October 7, 2004, the DER Partnership and SCE hosted a second workshop at SCE's CTAC facility in Irwindale, California. Its purposes were to:

- report on the working group's recommendations for a successful RFP, based on its July workshop and the work of its two Issue Groups over the summer
- report on SCE's perspectives and current plans for the RFP
- move toward consensus on any outstanding issues identified by the working group
- hear stakeholder perspectives of the value and results of the collaborative process

Most of the Collaborative participants returned for this workshop, and some who could not join the July workshop were able to attend this one.¹⁷

SCE opened the workshop by reiterating the importance of this project to begin integrating new thinking and technology into its vision of the utility of the future. Russ Neal, SCE's Manager of Distribution Engineering, stressed that much remains to be learned about the technical design of tomorrow's grid, but the most difficult questions will concern the business model needed to achieve future grid objectives, including who will own the equipment and access the benefits, and how costs will be recovered. Russ observed that if these issues are not addressed, utilities will simply replace today's grid with more of the same technology, design and thinking that date back 50 to 100 years.

SCE announced that it has embarked on planning for a "Circuit of the Future" project in its service territory, near San Bernardino. The project will rebuild an existing circuit to incorporate new technologies that will allow SCE to understand and control the utility-owned equipment that delivers power along that circuit. It will also incorporate and use customer-owned DG. SCE invited DG developers present at the meeting to work with the utility to test concepts for using customer-owned capacity to defer SCE investment in expanding its own capacity in the area. The utility is also prepared to test hardware (such as control switches) that will be needed to 'physically assure' contracted load reduction as discussed in the Collaborative.

¹⁷ Appendix F contains the attendance list for the October Workshop; Appendix G reproduces the summary report of the Workshop; and Appendix H includes copies of available presentations from the Workshop.

SCE also announced that it would be submitting the new Model Agreement worked out during the Collaborative for CPUC approval, since the Collaborative's input had resulted in major modifications to the agreement the utility had filed in 2003. This submittal, as well as recent changes in SCE's distribution planning cycle, would delay issuing the DG RFP until spring 2005. The first expansion projects that might be deferred by the program will be those planned for construction in 2006-2007.

Presentations at the October workshop (included in Appendix H), reported that over the summer and in the days preceding this meeting, the two Issue Groups had resolved virtually all of the important near-term issues identified as high priorities at the July workshop. Stakeholders at the October 7 meeting worked through a number of additional details regarding customer notification, facilitation of contacts between customers and developers, disclosure of SCE's market reference price, and the exemption of planned customer maintenance periods from 'physical assurance' requirements.

Evaluating the Process – What Worked Well and What Can Be Improved

Participants in the October 7 workshop were asked to evaluate their experiences with the DER Partnership collaborative process during this DER pilot project. They were asked to comment on the successes of the stakeholder collaboration approach, the limitations or frustrations they experienced, and their suggestions for improving the process or achieving the goal of integrating significant amounts of DER into the electricity enterprise. Their responses are highlighted below.

What Worked Well

- The Collaborative was a very high quality group that included the right mix of DG manufacturers, project developers, public representatives and utility representatives.
- The organization of the workshops and the follow-up approach of focused Issue Group conference calls with specific agendas worked well to accomplish the Collaborative's objectives.
- Developers came away from the process with a much better understanding of how utilities plan and operate their distribution systems. They gained perspectives on utility operations that they had not heard before.
- The collaborative effort accomplished a lot. Although its ultimate success cannot be judged until the RFP is issued and customers are enrolled in the program, developers were hopeful that the process will lead to DG opportunities for their companies.
- Stakeholders felt that SCE was open to input and very supportive of the process. Many had previously interacted with SCE only in adversarial CPUC or CEC proceedings, and were pleased with the more constructive approach of this forum.
- SCE participants learned much that they had not known about what issues were important to DG providers and prospective DG customers. They realized that traditional utility approaches and methods of operations will need to be made more flexible if the program is to reach its potential.

- All participants felt that the collaborative quest for win-win solutions had led to a productive, collegial approach throughout the process. Getting stakeholders together to identify and work through issues helps everyone avoid some of the failures that have dogged similar attempts in other parts of the country.
- The SCE Model Agreement that resulted from the Collaborative's work is a much better document, with a much higher chance of success.

What Could Be Improved

- Some developers expressed disappointment that the pilot would engage only a small number of SCE customers (perhaps 20, with potential for 1 to 20 MW projects) and the value of short-term deferral payments (probably 5-20% of project cost) would be relatively low.
- Some stakeholders were frustrated by SCE's need to delay issuance of the RFP beyond the Fall of 2004 in order to seek CPUC review of the new Model Agreement, and to mesh it with the utility's new planning cycle.
- Developers and vendors would have preferred to see data from the actual projects that SCE might call on them to defer. Some felt that using sample data from 2003 projects made the effort more abstract than they would have liked.
- Stakeholders would like to see involvement from Pacific Gas & Electric as well as SCE.
- This process is useful as a short-term approach, but stakeholders need a sustained long-term commitment – at least five years – to build a successful business.
- Mainstreaming DER solutions will require a simpler process without legal entanglements and complicated customer requirements.
- More attention could have been given to SCE's process for identifying target areas and potentially deferrable upgrades, which some thought could overlook certain high value projects.
- Too few customer representatives participated in the Collaborative; more customer perspectives would be helpful.

Identifying Next Steps

Participants in the October 7 workshop suggested a number of next steps to increase DER deployment on the grid. Stakeholder suggestions included the following:

- Educate other utilities on the value of DER and how they can benefit from its deployment. The DER Partnership should conduct workshops with utilities across the country.
- Adapt the learning and experience from this collaborative pilot to a simpler model that other jurisdictions can easily replicate
- Design regulatory approaches that allow DER to compete on an equal footing with utility construction. Look for analogies where utilities were compensated for lost revenues from DSM programs in the 1970's and 80's.

- DG needs to identify a ‘killer application’ to drive widespread market adoption.
- In today’s environment, encouraging customer-side DER is not in the interest of utility shareholders because it results in revenue loss and erodes utility earnings. Utilities will not embrace DER unless it offers financial returns at least equivalent to their other investments. Come up with a pilot model that makes utilities at least neutral to DER, by ensuring that utility DER investments that benefit ratepayers can earn returns at least equivalent to utility T&D assets.
- Change regulatory rules so utilities can make money on sensible DG, no matter who owns it.
- Design a DER portfolio standard similar to renewable portfolio standards adopted by many states.
- Construct a business model that yields 10-12% returns and Wall Street money will be there.
- Proactively pursue integrating DG supply, demand management and demand response into California’s IEPR planning process and develop ways to implement the California Energy Plan’s loading order (efficiency, renewables, demand response, distributed generation, etc.) Conduct a workshop on this as part of the IEPR process.

7

ACHIEVEMENTS, FINDINGS & RECOMMENDATIONS FROM THE CALIFORNIA PILOT PROJECT

Achievements of California’s DER Collaborative Toward a Successful DG Solicitation

The stakeholder collaborative approach was a significant factor in achieving the successes of the California DER Pilot Project that can be measured to date. The pilot project demonstrates the ability of the stakeholder collaborative process to create innovative and robust solutions that address all stakeholder interests. The approach of stakeholders partnering together to find win-win solutions provides a distinct advantage compared with the typically adversarial mode seen in proceedings and hearing rooms. Working together as partners builds trust and understanding of each other’s perspective. This helps to develop solutions that provide each stakeholder an opportunity to benefit.

Several achievements can be attributed to the collaborative approach:

1. The reliability requirement for “physical assurance” has been made more flexible: instead of requiring load reduction or “demand limitation” at all times when the distributed generator is not operating – which can create real burdens for customers otherwise willing to help the utility – SCE will limit the requirement to 200 to 400 hours per year, with a daily limitation as well, and will make allowances for customer maintenance outages.
2. DG customers and third-party providers need to know whether it’s worth the considerable time and expense it will take to respond to a utility DG solicitation. SCE’s starting point was that no price or value would be included in its RFP, and proposals would be considered sealed bids, to take or leave. Based on the Collaborative’s input, SCE will now include a ‘market reference price’ to guide customers, and will negotiate the final agreement with successful proposers.
3. The Model Agreement to be entered into with successful proposers was originally designed such that the utility would take virtually none of the risk. Collaborative discussions persuaded SCE to rewrite it to share more of the risks, and collaborative participants are satisfied that it meets many of the needs of prospective proposers.

These and other achievements of the Collaborative are documented in Table 7-1.

**Table 7-1
Collaborative Achievements**

| Topic | Initial Status | Final Results |
|---|--|--|
| Model for successful DG solicitation | Initial response from CA IOUs to CPUC Order did not address all stakeholder needs or capabilities | DER Partnership stakeholder-driven process has engaged participants in defining their needs, recognizing co-parties' needs, and seeking common ground |
| Communication among stakeholders | Participants wary. Based on previous experiences skeptical that progress could be made | Participants openly communicate, are willing to listen, share and address problems jointly |
| Utility distribution planning process | Non-utility participants knew little about utility planning | Non-utility participants better understand utility service obligations, planning horizons and uncertainties, and investment process |
| Value of DG to utility & providers | Most participants unfamiliar with timing & valuation issues affecting utility deferral, or driving DG investment | Factors influencing DG value to utility are better defined; valuation methodology now explicit, and tools accessible; range of grid values explained; DG provider investment concerns explored |
| Information needs | Utility uncertain what info DG providers need to prepare responsive proposals | Specific types of information identified as critical to DG providers to allow rational participation, including physical location and deferral value in the form of a 'market reference price' |
| Confidentiality issues | Utility cautious about sharing information regarding system upgrade costs, needs or customers | 2-step process proposed to qualify respondents and require non-disclosure agreements, to limit recipients of sensitive information |
| DG procurement process | Exclusive focus on traditional RFP approach | Considering alternatives to RFP approach for next solicitation, using credits, tariffs, etc. |
| Recognizing multiple DER values | Initial utility proposal did not address importance of multi-program participation to DG providers; would have foreclosed opportunities. | Considering ways for customers / providers to receive value from other programs for <i>generation</i> -related benefits (e.g., curtailment), in addition to <i>distribution deferral</i> value from this program |
| Recognizing non-DG demand response | RFP limited to capacity supplied by DG-only | If DG is used to meet critical loads, additional demand response resources may be offered to meet utility's needs |
| Reliability requirement | Initial 'physical assurance' concept required customer to drop its load whenever DG is down – 24 x7, 8760 hours/year | Customer commits only for utility's peaking needs, perhaps 200-400 hours/year, estimated in advance by month, hours of day, etc. with adequate provisions for maintenance of DG facilities |
| Matching DG providers & utility customers with potential host sites | Utility had not identified the need to assist | Utility willing to invite customers to request to be contacted by qualified respondents |
| Matching utility deferral needs with proposers' investment needs | Payments for 1 or 2-year deferral considered inadequate to assist project financing | Two-year agreement with right of first refusal or renewal option if deferral remains utility's least-cost or best-fit option may enhance attractiveness of customer participation |
| Response time for DG solicitation | Driven exclusively by utility planning cycle | Driven by combination of utility planning needs and developer time requirements to put projects together |
| Regulatory oversight of process | Strict literal interpretation of Commission directives to minimize utility regulatory risk | Recognition that Commission intent is better served by more flexible win-win approach supported by participants and regulatory staff |
| Cost to assure responsive load reduction | Host customer to absorb 100% | Utility to finance its portion of notification and control system costs, & deduct from deferral payments |

| | | |
|---|--|--|
| Model contract between utility and successful proposers | Model agreement prepared solely by utility; presented serious business issues for DG providers | Model agreement rewritten and much improved from both utility & DG provider viewpoints |
| Overall project risk | To be borne almost entirely by DG customer / developer | To be allocated between utility and DG customer / developer as necessary to elicit win-win responses |

Framework-Recommended Initiatives Addressed in This Pilot

E2I’s *Framework* report described a process for designing effective DER initiatives, and it presented a wide range of collaborative options. The California Pilot Program focused on a subset of these necessary activities. It was created specifically to help SCE structure a response to a 2003 CPUC Order that required utilities to evaluate DG as a distribution alternative and take steps to procure it where it appears viable, and the Collaborative’s activities were shaped by the scope of that Order.

The 2003 Order addressed DG rather than the more inclusive category of DER. It focused on the use of DG as an alternative to distribution capacity expansion, but not on other value streams that DG might offer (e.g., transmission congestion relief, wholesale price mitigation). It directed an RFP solicitation process, rather than one that involved tariff changes, localized incentives or distribution credits. And it adopted a requirement for ‘physical assurance’ and a specific formula for calculating the value of DG to the utility. These boundary conditions broadly defined SCE’s procurement challenge, and the Collaborative was designed to help SCE successfully meet it.

Table 7-2 on the next page summarizes the range of activities that *DER Framework* document recommended for a comprehensive approach to DER market integration. It shows which of them the SCE project addressed, and which remain to be addressed by future collaborative efforts.

Table 7-2
Framework Initiatives Addressed by California Pilot Project

| DER Framework Initiatives (from <i>Framework</i> report, Chapters 3 and 4) | SCE Pilot Activities ● – addressed ◐ – partially addressed ○ – not addressed |
|---|--|
| Structuring the Collaborative Process | |
| – choosing the participants | ● |
| – defining ground rules & structure | ● |
| – setting objectives and priorities | ● |
| – evaluating success | ● |
| Analyzing Costs and Benefits (using DER Partnership Cost-Benefit Tool) | |
| – tailoring tool to local conditions | ◐ |
| – using tool to adjust regulatory incentives, reallocate costs and benefits | ○ |
| Basic Program Strategies | |
| – Leveraging DER values <ul style="list-style-type: none"> ○ For DER customers (<i>bill savings, renewable energy credits, energy sales, demand response programs, etc.</i>) ○ For utility shareholders & other ratepayers (<i>reduced wholesale purchase costs, avoided generation, transmission or distribution costs, ancillary services, etc.</i>) ○ For society generally (<i>reduced emissions, increased network reliability, etc.</i>) | ◐ |
| – Introducing efficient incentives <ul style="list-style-type: none"> ○ For customers & DER providers (<i>bilateral contracts, load reduction tariffs, standby waivers, environmental adders, hourly pricing arrangements, etc.</i>) ○ For utilities to actively facilitate DER (<i>cost recovery, revenue loss treatment, rate-of-return adders, decoupling, etc.</i>) | ◐ |
| – Eliminating barriers <ul style="list-style-type: none"> ○ permitting and interconnection ○ Market barriers (<i>access to wholesale markets, area- and time-specific pricing, offsite energy sales, etc.</i>) ○ Transactional barriers (<i>lack of flexibility, need for simplified processes and model contract provisions, etc.</i>) | ● |
| Rate Design & Regulatory Incentives | |
| – volumetric vs. fixed charges & demand charges | ○ |
| – short-run vs. long-run pricing | ○ |
| – Standby rate methodologies (<i>demand subscription, non-firm standby, etc.</i>) | ○ |
| – two-part rate designs (<i>historical billings + marginal pricing for usage changes</i>) | ○ |
| – recognizing additional DER benefits <ul style="list-style-type: none"> ● distribution deferral ○ other locational benefits ○ energy value ○ ‘generation multiplier’ effects ○ ancillary services ○ potential emissions reductions | ● |
| – efficient market rules to recognize customer-provided benefits | ○ |
| – rate decoupling through PBR | ○ |
| – experimental pilot incentives | ◐ |

Lessons for Moving Forward with DER Market Integration

1. Focus on Sources of Value by Capturing Value Streams to All Stakeholders

Customer-side energy solutions, including DG, can provide value in the form of reduced energy costs, enhanced reliability, power quality and/or environmental stewardship for the host customer. However, to bring forth distributed energy solutions on a scale that will significantly impact the larger electricity enterprise, other potential value streams must be captured – not only by host customers, but by some combination of the utility, its other customers, and society at large. Examples of these value streams are deferred or avoided capital investment in distribution, transmission and/or generation; reduced prices for grid-supplied energy at constrained times and places; and environmental benefits from some distributed technologies.

Given today's technologies, economics and regulatory conditions, the approaches that most readily yield or capture such values include:

- Energy efficiency measures
- Combined heating/cooling and power (CHP) or tri-generation
- Demand response where there are spikes in peak power costs

2. Simplify the Process that Distribution Utilities Use to Procure DER

Create standard tariffs or credits that confer value for customers who limit their demand in areas where utilities will otherwise need to construct capacity additions or circuit upgrades. Make these tariffs or credits available for a defined period that more closely aligns with the long-term value of the resource than with the short-term deferral value of any single project.

The RFP approach pursued in the California pilot project probably is not the simplest or most efficient process for procuring DER. Its focus on short-term projects that address narrowly defined needs further limits its usefulness. In order to unleash the potential of these resources, stakeholders should:

- Consider a longer-term planning horizon (e.g. five to ten years instead of two). This would support DER/DG financing, and allow new customer resources to be built up gradually as marketing programs pick up momentum.
- Solicit and accept distributed solutions targeted at entire utility planning areas, rather than at specific circuits or substations.
- Create targeted tariffs or distribution credits for planning areas whose demand is growing in ways that DER can help address. Structure these mechanisms to meet the specific growth issues confronting each planning area (e.g., peak growth, baseload capacity, etc.)

3. Adopt a Long-Term Perspective

A major challenge in the California pilot project was that utility planners could not comfortably forecast local distribution needs more than two or at most three years out. For SCE, load growth

driven by economic cycles and large new developments can be unpredictable, and forecasted needs can change quickly. Given the CPUC's focus on short-term distribution capacity deferrals for this procurement, it was difficult to consider longer-term benefits in valuing distributed resources for the utility system.

DER needs a longer-term planning and implementation horizon in order to succeed. It needs a proactive approach to integrating small resources into long-term energy supply networks, which could build on the following steps.

Design a total resource planning approach that includes three elements—saving, buying and building resources. Encourage a least-cost/highest-value approach to procuring and ensuring reliable supply. Adopt incentives that encourage grid operators to promote energy efficiency (save) and to share on-site customer resources that can be managed or dispatched (buy), as well as traditional approaches that default to adding new central generation, transmission or distribution facilities (build). Consider grid operator- or distribution utility-owned distributed generation on the grid as one of the options of a total resource planning approach.

For nearly a century, regional electricity systems in the U.S. have been highly centralized. To enhance and supplement these systems with distributed resources requires sophisticated planning and integration, with respect to both central station approaches and alternative distributed solutions. A prime goal is to use each type of resource optimally, in applications where it contributes the highest value relative to other solutions. To advance this goal, stakeholders should:

- Design a total resource planning approach that builds distributed resources into some desired mix of 'save some, buy some, build some';
 - Identify an appropriate mix of centralized energy sources, energy efficiency, distributed generation, CHP and demand response;
 - Design programs to coordinate and optimize the interactions of the distributed sub-components; and
 - Integrate DER into distribution planning processes and geography by targeting distribution planning areas rather than circuits or substations. DER must become a long-term approach to a regional electricity reliability concern, not simply a replacement for project X or project Y.
4. Provide Economic Incentives for Utilities to Use the Most Cost-Effective Resources, Including Customer-Side Resources, to Serve All Customers

Utilities (particularly distribution companies) often see reduced revenue when customers adopt distributed generation or load management technologies. Most current regulatory schemes tie utility earnings directly to energy throughput and capital investment. These regimes discourage utilities from responding to increasing consumer demand with better asset utilization (and thus increased efficiency). Solutions based on more efficient asset use typically pay customers to control their facility's demand at times of high system demand, or modify pricing structures to encourage this behavior. Utilities that adopt these sensible strategies for their delivery business often are rewarded with lower earnings for their shareholders. This must change to enable DER

solutions to compete fairly within the traditional electricity enterprise: the regulated business model needs to encourage utilities to support, integrate and adopt distributed solutions where they make sense for utility customers and society at large.

State-regulated investor-owned utilities must serve the public interest. To remain viable business entities, they must also serve the interests of their investors. Where public interests diverge from investor interests, or long-term objectives appear incompatible with short-term ones, progress requires recognizing these tensions and re-aligning stakeholder interests. Representatives of diverse stakeholder interests in the recent California DER pilot project urged a more active role for utilities in facilitating and coordinating DER development, and in integrating it with conventional utility operations. As in earlier DER Partnership gatherings, they stressed that in order to engage utilities as DER advocates, facilitators, integrators, and adopters, stakeholders must find ways to:

- Reward utilities financially for creating and managing a least-cost approach to the overall delivery of energy, including both electricity and other useful energy forms.
 - Remove disincentives for utilities to incorporate customer demand reduction initiatives as a resource to manage their systems. One of the clearest disincentives is tying utility investment returns primarily to utility- built and -owned facilities (although Collaborative participants generally supported this as one possible alternative).
 - Work with State regulators, utilities and other stakeholders to develop and adopt new approaches to utility ratemaking that will advance these objectives.
5. Expand Facilitated Stakeholder Collaboration to Bring Diverse Interests Together, and More Actively Engage Energy Customers and Regulators

Stakeholders involved in the California pilot strongly endorsed the collaborative model the DER Partnership has used successfully for over two years. They urged its continuation to:

- Bring together interested stakeholders, and more actively engage customers, regulators and their staffs
- Pursue other elements of DER Framework methodology that were tabled in order to focus on SCE's 2004 solicitation process¹⁸
- Facilitate informal working groups of experienced professionals representing key stakeholder views, working together closely to design pilot programs to benefit from the lessons learned here and implement the ideas described below.

The California pilot has once again affirmed the advantages of the collaborative model. As SCE and other utilities have acknowledged, large regional utilities embody decades of bureaucratic adaptation and enormous inertia. This is especially true of regulated utilities, whose activities are continuously subject to review, analysis and oversight through formal – and usually adversarial – regulatory proceedings. These are usually judicial or quasi-legislative forums governed by strict procedural rules and intended to yield formal outcomes that the parties can act on or challenge. They serve important and useful purposes – but they rarely encourage open, unguarded dialogue;

¹⁸ See Table 7-2 on p. 7-4.

clarify misunderstandings; acknowledge that improvements are possible; build consensus from conflict; or seek ‘win-win’ solutions that benefit multiple stakeholders.

Stakeholders in this collaborative pilot project concluded that it had done all of those things, and done them well. Virtually all who commented strongly favored this approach over formal regulatory proceedings, believing that it is far more likely to nurture constructive business models and generate innovative DER solutions.

Specific Ideas for Future Consideration

Based on the findings of the pilot project and the recommendations of the *Framework*, the following concepts are offered for input and discussion.

1. Develop a nationally-based stakeholder collaborative to encourage win-win business and regulatory models that incentivize utilities to use all forms of distributed energy resources and reward DER customers fairly.

This stakeholder collaborative would focus on the concept of win-win DER integration and provide a forum for building momentum and moving it into mainstream thinking. It would consist of government agencies, state regulatory commissions, the National Association of Regulatory Utility Commissioners, utilities, DER suppliers and developers, and customers.

Primary activities would include:

Win-win model development. The collaborative would explore models that reward the players, including utilities, for integrating distributed energy resources, including distributed generation, storage, energy efficiency, and load management. These models would provide options for states to select or build upon to fit with their particular needs. Concepts for discussion include:

- Recommend a regulatory mechanism to encourage utilities to adopt DER where appropriate.
- Design pilot tariffs to enable utilities that now earn returns on self-invested capital to earn equivalent ‘phantom’ returns on DER investments that displace poles, transformers or wires.
- Consider allowing utility returns on customer DER investments or credits paid to customers.
- Consider rate-of-return adders for utility DER investment that meets predefined criteria for efficiency, environmental benefits, congestion relief, system support, or other characteristics
- Develop standardized methodologies to design customer incentives for DER targeted to stressed distribution points.

Workshops. Workshops to build interest and participation and to conduct brainstorming sessions will feed the model development. Best practices will be shared and documented. Workshops provide opportunities for outreach.

DER Value Assessment. The collaborative provides a forum to vet approaches for determining value and measuring success. The collaborative will:

- Develop standardized approaches for determining the value of utility distribution deferrals, and ways that utilities can prioritize their construction projects.
- Design appropriate measurement criteria (asset utilization, reduced budget, etc.) to judge the success of pilot programs and other DER deployment initiatives.

For the national collaborative, the DER Partnership will:

- Convene the collaborative, consisting of a working group of stakeholders
 - Provide background and analysis for concept development and facilitate working sessions to innovate new or improved concepts
 - Hold workshops for broader audiences to build momentum, share experiences, and brainstorm new ideas
 - Provide DER value and measurement approaches for assessment by the collaborative
2. Linked to the national collaborative, develop regionally-based stakeholder collaboratives to develop and implement regional approaches to innovative DER solutions.

Collaboratives representing states, or regions comprising multiple states, would develop win-win models for encouraging DER integration to meet regional needs. States with high interest, such as California, Massachusetts, and New York, or regions such as the Northeast, are likely initial focus areas. The regional collaborative would link to the national one to benefit from its work, supply input, and consider options.

In California and New York, regulatory agencies have directed the approach to procuring DG as a distribution alternative. In New York, the RFP approach has so far had little success. In California, utilities have somewhat more flexibility, but stakeholders agree that simpler, broader approaches should be considered.

The collaborative approach will build directly on shared stakeholder experience and enable innovative thinking ‘outside the regulatory box’ by parties with different perspectives working cooperatively toward an outcome that benefits each stakeholder.

EPRI recommendation is to:

- Convene a working group of stakeholders
- Provide background and basis for concept development
- Facilitate working sessions to innovate new and refined concepts
- Support the working groups with analysis by the DER Partnership Project Team
- Document the process and findings
- Develop presentation materials for stakeholders outreach
- Conduct outreach to share results and encourage states to apply the findings in their jurisdictions.

The regionally-based collaboratives would consider concepts such as the following:

- a. *Develop a viable business model for utilities and other stakeholders to benefit from a proactive utility role in facilitating, coordinating, integrating and developing grid- and customer-side DER.*

Develop innovative mechanisms to reward utilities for successfully managing and coordinating economically and environmentally appropriate approaches to supply and demand portfolio management. The portfolio incorporates DER technologies and applications regardless of ownership. DER includes renewables and other distributed generation technologies, demand management, and energy efficiency. Work to remove utility disincentives to encourage demand reduction to help manage their systems. Develop and adopt new ratemaking or incentive approaches to advance these objectives.

- b. *Develop a tariff-based credit for DER located in targeted areas.*

Determine how such a credit would be implemented, and how to incentivize utilities to support or be indifferent to the approach. For example, utilities that now receive returns on self-invested capital might receive a ‘phantom’ return on DER investments that replace poles, transformers or wires.

- c. *Design and implement a process to include distributed generation, renewables, combined heating/cooling and power, demand response, and energy efficiency in target area programs.*

Use all-resource planning techniques to suggest appropriate portfolio mixes for various types of DER in combination with conventional system resources to capture, for example, the value of distributed installations to the distribution grid. Once an optimal portfolio is determined, adapt market rules so that the value of the identified DER solutions can be monetized by market participants.

- d. *Design and implement an approach for targeting system benefit charges and other public incentives to locations with the highest grid value.*

Work with interested utilities to assign a value to DER investments in selected areas of the utility service territory. For example, work with California to redesign its Self-Generation Incentive Program to offer higher incentive payments to projects located in targeted utility planning areas or other designated regions of the state, or with the Massachusetts Technology Collaborative to design DER incentives to target high value areas of the Massachusetts grid. Design approaches to target renewables meeting RPS requirements to locate at high value locations within the distribution grid.

- e. *Develop mechanisms to incorporate DER/DG solutions into regional generation and transmission adequacy planning.*

Use all-resource planning techniques to suggest appropriate portfolio mixes for various types of DER in combination with conventional system resources. Once an optimal portfolio is determined, adapt market rules so market participants can monetize the value of the DER solutions identified.

3. Apply the stakeholder collaborative process to demonstration programs to test concepts in the field, quantify DER costs and benefits, and measure success of specific projects or programs.

Develop stakeholder collaboratives to work closely with states, utilities, and others demonstrating DER in the field. The intent for this work is not to lead or fund demonstration projects, but to work in collaboration with them. Stakeholders will guide and review the process of understanding and quantifying value. They will provide input to the quantification of costs and benefits, since a benefit to one stakeholder may be a cost to another. Stakeholders will provide credibility to the process. Through involvement in the process, stakeholders will gain understanding of other stakeholder's perspectives and thus open the door for creating new approaches for successful win-win strategies that can be applied in these and subsequent projects.

EPRI recommends to:

- Convene a working group of stakeholders to field-test concepts
- Arrange to collaborate with DER projects in the field or in progress
- Provide analysis and facilitate assessment and collaboration to determine value and measure success.
- Document and provide outreach materials and opportunities to build industry agreement

Opportunities include:

a. Demonstrating the cost and benefits of win-win DER projects

Southern California Edison will take a soft-start approach, tapping into customer-owned DER systems to test their capability to provide distribution services to defer system upgrades. Work with SCE and DER stakeholders to guide development of win-win demonstration projects, provide input on operations, customer agreements, and other project elements. Quantify costs and benefits, and document lessons learned and recommendations for successful win-win DER projects.

Work with other state organizations that have funded CHP, renewables, and similar projects (such as NYSERDA's CHP projects in New York). EPRI will convene stakeholders and provide working tools and expertise to guide cost and benefit quantification, and will document lessons learned and recommendations for DER projects benefiting multiple parties.

b. Demonstrating the value of DER in the Circuit of the Future

Southern California Edison is proceeding with a program to demonstrate and test a distribution 'Circuit of the Future', which will include both distribution and generation technologies. Work with SCE and other stakeholders to facilitate and structure

demonstrations of technologies that provide distribution services. Quantify the value that DER provides on this Circuit of the Future.

c. Demonstrate the value of optimizing a supply and demand resource portfolio

In conjunction with SCE's Circuit of the Future work, collaborate with SCE and other stakeholders to demonstrate how distributed generation and customer-side demand management and energy efficiency programs can be used to optimize an integrated supply and demand portfolio. Contribute expertise and guide collaboration on ways to incentivize customers to adopt solutions that strengthen the portfolio. Demonstrate approaches to optimize supply and demand on local electricity systems. Quantify the value of the optimized portfolio, and provide lessons learned and recommendations for other jurisdictions.

A

CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP PARTICIPANTS

Working Group Participants:

Developers

1. Kevin Best, Real Energy (Substitute: Robin Luke)
2. Tom Drolet, DTE Tech
3. Chach Curtis, Northern Power Systems
4. Jeff Lyons, US Power
5. Gordon Savage, Simmax Energy

Suppliers

6. Tod O'Connor, STM Power
7. George Wiltsee, Ingersoll-Rand
8. Eric Wong, Cummins *
9. Kevin Duggan, Capstone
10. Bob Bjorge, Solar Turbines

Customers/Customer Representatives

11. Justin Bradley, SVMG (Substitute: Jeff Byron) *
12. Gary Sparks, California Society for Healthcare Engineers
13. Howard Choy, LA County ISD (Substitute: Steve Crouch)

Utility

14. Stephanie Hamilton, SCE
15. Tom Dossey, SCE
16. Ishtiaq Chisti, SCE
17. Dan Tunncliff, SCE
18. Lynn Ferry, SCE

Advisors:

19. Valerie Beck, CPUC*
20. Mark Rawson, CEC
21. Nag Patibandla, NYSERDA*
22. Valerie Harris, CPS San Antonio*
23. Fran Cummings, Mass Tech Collaborative (Substitute: Gerry Bingham)
24. Tony Prietto, SDG&E
25. Saphir Hamilton, CHG&E*
26. Eileen Buzzelli, First Energy*
27. Pat Hoffman, DOE. (Designee: Joe Ianucci)
28. Jim Armstrong, NStar Electric & Gas Corp (Invited by Mass Tech Collaborative)

* Not available to attend July 13–15, 2004

DER Partnership Pilot Project Team:

29. John Nimmons, John Nimmons & Associates, Inc.
30. James Torpey, Madison Energy Consultants
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32. Dan Rastler, EPRI
33. Ellen Petrill, EPRI

B

CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP PRESENTATIONS

The presentations can be found on the EPRI website at the following link:
<http://www.epri.com/der-ppp/index.html>. This link provides the reports of the EPRI DER Public/Private Partnership. Click on [pilot project](#) for presentations from the workshops and other materials from the pilot project.

C

CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP ATTENDEES

| Name | Title | Affiliation |
|------------------|---|--------------------------------------|
| Armstrong, Jim | Program Manager | NStar Electric and Gas |
| Bingham, Gerry | Policy & Markets Coordinator, Renewable Energy & Climate Change Group | DOER, Mass. Div. of Energy Resources |
| Bjorge, Bob | Market Development Manager | Solar Turbines |
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| Counihan, Rick | Vice President | E2I |
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| Dossey, Tom | Project Manager, DER | SCE |
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D

CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP SUMMARY REPORT

Introduction

The Electricity Innovation Institute (E2I) held a well-attended and lively workshop for distributed energy resources (DER) stakeholders to solicit their ideas on how to structure a successful utility DER procurement in California. This workshop kicked off the California pilot project of E2I's DER Public/Private Partnership Market Integration program. Through this project, E2I and its partners are exploring ways to identify and implement win-win approaches for DER—with the goal of DER applications that benefit multiple stakeholders and no harm to other stakeholders.

Purpose

The goal of the pilot project is to support Southern California Edison's (SCE) objective of producing a request for proposal (RFP) for DER that results in successful proposals and meets specific needs of the SCE distribution system. The workshop established a collaborative working group of stakeholders to provide feedback on the solicitation process so that customers, customer groups, developers, manufacturers, and others can confidently propose DG solutions responsive to utility needs in a DER pilot that could serve as a model for utility DER procurements.

Attendees

Thirty-one stakeholders participated in the workshop, representing DER developers and equipment manufacturers, electricity customers, researchers, electricity utilities, and Federal and State energy agencies.

Major Outcomes

- SCE demonstrated commitment to develop an RFP that attracts bidders and results in successful bids. Vice President Jim Kelly urged stakeholders representing “‘both sides of the table’...often with some fairly strongly-held opinions about the likely intent of the potential counter-parties...to suspend those opinions...and let the facts speak for themselves.” Kelly told the group that “SCE is committed to solutions that make sense for our customers- all of them.” Strong support and participation from other key SCE personnel included Russ Neal, Manager, Distribution Engineering, and senior engineers and project managers from Distribution Engineering and the Customer Business Unit.

- Other stakeholders were also committed to providing input to SCE to achieve a successful RFP. While several participants began as somewhat skeptical, in the end, each stakeholder committed to work on the issues the group brought forward and prioritized.
- The highest priority issues identified by workshop participants were categorized and assigned to two issue groups:
 1. Business models and regulatory issues
 2. RFP process issues

Each stakeholder committed to join one of the two groups to analyze and discuss specific issues assigned to each group, and make recommendations to SCE for its consideration in developing the RFP.

- The stakeholders were concerned about a number of major issues that could make this RFP not particularly attractive to end-use customers. These will each be explored further by the issue groups.
 - Physical assurance—interpretation of the requirement to automatically interrupt a customer’s normal load when its distributed generation does not perform as contracted.
 - The value of distribution upgrade deferral, defined as the utility's carrying cost of deferred capital investment for the period of deferral —the service for which the utility would offer payment to the DER owner. In most cases, this service appears to have limited financial value and is not likely to provide the sole impetus to make a customer site project viable.
 - Self-Generation Incentive Program eligibility—currently, customers who have entered into contracts with the utility to provide distribution-related distributed generation service are not eligible for the self-generation incentive.
- The stakeholders raised several other possibilities that might help integrate distributed generation. These will also be explored further by the issue groups.
 - Utility ownership of distributed generation
 - SCE matching qualified developers with eligible customers
 - Combining demand response with distributed generation resources for distribution deferral

Workshop Approach

The 1½ day workshop was hosted by the E2I DER Public/Private Partnership and was held at SCE’s Customer Technology Application Center. E2I invited a working group of stakeholders that represent the types of organizations that might respond to the RFP. It also invited an advisory group of other stakeholders, including regulators, E2I Partners and their representatives and other interested utilities. Several advisors attended and contributed significantly in the workshop and will continue to work as members of the issue groups.

The workshop began with a roundtable of what each participant hoped to get out of the workshop. The responses included a successful RFP, a user-friendly RFP, increased business opportunities, creative new ideas, learning about the process, and advancing the integration of DER.

The first day of the workshop included an overview of the E2I Partnership highlighting the win-win goals of the program, plus example calculations of the value of deferring distribution upgrades and the costs and benefits of distributed generation projects. Strategies for collaboration and examples of win-win opportunities were described. SCE described its distribution planning process and key elements of the proposed RFP. Stakeholders each had a chance to express issues, needs, concerns, and desires. Throughout the day, issues that arose in discussion were recorded. At the end of the day, additional issues were captured and all issues were prioritized by voting. After the session, the E2I team categorized the issues into two groups.

On the second day, the working group and advisors concurred in the team's categorization, and each participant elected to join one of the two issue groups. Each issue group held its first meeting, further discussed the issues, and determined next steps. Each group will work via email and conference call to develop recommendations to SCE for improving the chances of success of the RFP. A workshop will be held mid-September to finalize the recommendations. The workshop ended with a closing roundtable, asking for last comments. Responses included appreciation for SCE's commitment and interest in making this process work, and affirmation that the collaborative process had so far been very valuable in helping participants understand each others' perspectives.

The discussions and results of this pilot program will be shared publicly. This report plus workshop materials and attachments will be posted on the E2I website at www.e2i.org . (Now <http://www.epri.com/der-ppp/index.html>)

Issue Groups

Stakeholders at the workshop on the second day joined one of the following issue groups. Stakeholders who were not in attendance on the second day are invited to join a group of their choosing and participate in the groups' conference call discussions. Please contact Ellen Petril with your choice and to receive information on the planned conference calls.

The following gives the prioritized issues of each group. Further details are available in attachments "Issue Group 1" and "Issues Group 2."

1. Business Models and Regulatory Issues

Near-Term Issues Requiring Resolution Before SCE RFP Is Issued

- a. Eligibility for incentives
- b. Physical assurance
- c. Eligible resources (e.g., DG or demand response)
- d. Feeder specific tariffs or distribution credits (fixed payments to participating customers) as alternatives to RFP
- e. Additional DG values

Longer Term Issues for Future RFPs

- a. Business model
- b. Physical assurance (e.g., alternative approaches to dropping load)
- c. Eligible resources

2 RFP Process Issues

- a. Availability of cost data and value of distribution upgrade
- b. Simplification of the RFP process and proposed contract terms
- c. Availability of distribution system data
- d. Length of contract
- e. Utility role in matching customers and developers

E

CALIFORNIA DER PILOT PROGRAM – SOUTHERN CALIFORNIA EDISON REVISED DRAFT MODEL DEMAND LIMITATION AGREEMENT

MODEL DEMAND LIMITATION AGREEMENT FOR UTILITY CUSTOMERS OPERATING DISTRIBUTED GENERATION FACILITIES

This Demand Limitation Agreement For Customers Operating Distributed Generation Facilities (“Agreement”) is entered into by and between (*Customer’s Name*) a (*Form Of Entity & State Of Registration*) (“Customer”), taking electric service at (*Customer’s Electric Service Address*) , under electric service account number _____, and utility (“Utility”), a California corporation. Customer and Utility are sometimes also referred to in this agreement jointly as “Parties” or individually as “Party.” in consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

1. APPLICABILITY

This Agreement provides for a customer who supplements the electric service it receives from Utility with electric power provided by a generating facility connected directly to the customer’s electrical facilities to place all or a portion of its electrical load under the physical control of Utility. Utility will pay a negotiated fee referred to as a “deferral credit” to customers for allowing such control. The terms of this Agreement are location and time specific and available only to customers connected to a portion of Utility electric system where Utility has determined in its sole discretion that the specified demand limitation controls are an acceptable alternative to the construction, expansion, or reinforcement of its electric system. This Agreement requires the Parties to install and operate control systems and facilities that will allow Utility to physically limit the amount of electrical capacity a customer may demand from Utility during various periods and under conditions as determined necessary by Utility. This Agreement does not address or provide for the interconnection of a customer’s generating facility, the purchase or transmission of electric energy produced by a generating facility, or the provision of electric service by Utility to a customer. Other agreements providing for such arrangements are available and may be formed by the parties as desired and necessary.

2. DEFINED TERMS

- 2.1 Commission: The California Public Utilities Commission
- 2.2 Deferral Payment: The payment(s) made by Utility to customer for placing its electrical load under the physical control of Utility during the term of this Agreement thereby allowing Utility to defer the expansion or reinforcement of portions of its electrical system.
- 2.3 Deferred Upgrade Facilities (DUF): The specific facilities and portions of Utility’s electrical system, including, but not limited to, lines, transformers, switches, and breakers that may be deferred as a result of the load limitation provisions provided under the terms of the Agreement.
- 2.4 Demand Limitation Period (DLP): The individual periods of time as established from time to time by Utility during which Customer is required to limit the amount of capacity demanded from Utility’s electrical system.
- 2.5 Demand Limitation Control System (DLCS): Customer’s automatic or manual system and procedures used to control its electric loads and Generating Facility during DLPs.

- 2.6 Demand Limitation Notification System (DLNS): Utility’s facilities, including metering, monitoring, communication and control devices, a portion of which shall be installed at Customers location and interfaced with Customer’s DLCS, used to communicate the initiation and termination of DLPs and monitor Customer’s electrical load.
 - 2.7 Firm Service Level (FSL): The maximum level of electric capacity designated by Customer to be demanded from Utility’s electric system during DLPs.
 - 2.8 Generating Facility: All of the equipment and facilities that comprise Customer’s generating facility and used by Customer as desired to provide electric service to its loads.
 - 2.9 Operating Year: Each 12 month period this Agreement is in effect following the “start” date set forth in Section A.3.2.a.
 - 2.10 Physical Assurance Separation System (PASS): All of Customer’s relays, transformers, circuit breakers, wiring, cabinets, conduits and appurtenant equipment deemed necessary and required by Utility to cause all or a portion of customer’s electric system to be automatically disconnected from Utility’s electrical system should customers electrical demand exceed its FSL during a DLP..
 - 2.11 Scheduled Outage Day: Any full calendar day designated by Customer and scheduled with Utility during which a DLP may not be initiated so as to allow for the maintenance of Customer’s Generating Facility, DLCS, or PASS.
3. SUMMARY AND DESCRIPTION OF CUSTOMER’S GENERATING FACILITY, ELECTRIC LOAD, DEMAND LIMITATION CONTROL SYSTEMS, AND THE DEFERRED UPGRADE FACILITIES
- 3.1 A description of Customer’s DLP performance requirements, conditions, and restrictions, required initial operating dates for Customer’s Generating Facility, DLCS and PASS, and the establishment of Customer’s FSL is set forth in Appendix A.
 - 3.2 A description of Customer’s Generating Facility including a single-line diagram showing the general arrangement of how Customer’s Generating Facility and loads are interconnected with Utility’s distribution system is set forth in Appendix B.
 - 3.3 A description of Customer’s DLCS and PASS, including a summary of their significant components, written operational overview, and a single-line diagram showing how Customer’s loads are connected and controlled by the DLCS is set forth in Appendix C.
 - 3.4 A description of Utility’s DUF, including a single-line diagram and map or plot plan showing the portion and significant components of Utility’s electric system which upgrade or expansion is deferred by the provisions of this Agreement is set forth in Appendix D.
4. TERM AND TERMINATION
- 4.1 This Agreement shall become effective as of the last date entered in Section 18. The Agreement shall continue in full force and effect until (Negotiated Termination Date), unless terminated pursuant to the terms of Section 4.4, or unless the Parties agree in writing to extend or reduce the term of the Agreement.
 - 4.2 Any obligation of one Party to the other, including any payment obligations, as a result of this Agreement, which accrued prior to or as a result of termination of this Agreement, shall survive termination.
 - 4.3 Prior to the termination date set forth in Section 4.1, and before entering into similar arrangements with another similarly situated and located customer to provide the demand limitation afforded under this Agreement, Utility shall evaluate the requirements for the continued safe and reliable operation of its electric system and, if Utility determines continuation of this Agreement in its original form or as may be amended, contributes to such operation, offer to extend the terms of this Agreement with Customer, subject to the following adjustments:
 - a. The term shall be extended to reflect Utility’s then-current forecast of its needs for construction, expansion or reinforcement of the portion of its system supported by this Agreement.
 - b. The Deferral Payment shall be adjusted to reflect any change in Utility’s projected cost of capital, and of construction, expansion or reinforcement of the affected portion of its system during the extension period.
 - 4.4 This Agreement may be unilaterally terminated by Utility earlier than the date stated in Section 4.1 upon the occurrence of any of the following:
 - a. Customer fails to comply with the terms of Section A.1.

- b. Customer fails to take all corrective actions specified in Utility’s Notice that Customer’s Generating Facility, DLCS, or PASS is out of compliance with the terms of this Agreement within the time frame set forth in such Notice.
 - c. The electric service account through which Customer’s Generating Facility is interconnected to Utility’s Distribution System is closed or terminated.
 - d. The agreement providing for the interconnected operation of Customer’s Generating Facility is terminated.
- 4.5 During the term of this Agreement, Customer shall inform any prospective successor electric service customer, if known, of the limitations imposed by this Agreement and that Utility may not be able to meet the successor customer’s full electric service needs until its electric system is reinforced or upgraded. Customer shall inform such entities prior to the sale or transfer of Customer’s property or facilities that receive service through the electric service account to which customer’s Generating Facility is interconnected, and/or before Customer’s electric service account is closed and transferred to another party.
5. DEMAND LIMITATION AND PHYSICAL ASSURANCE REQUIREMENTS
- 5.1 Except as specifically limited by the provisions of Section A.3.2, Utility may initiate a DLP at any time deemed necessary by Utility to maintain the loading limits of those portions of Utilities electric system directly affected by the absence of the DUF. Such loading limits shall be based on Utility’s established design criteria and material and equipment specifications. Except for the monthly testing provisions set forth in Section 5.5, Utility shall not initiate a DLP for any other purpose.
 - 5.2 Utility shall attempt, in good faith, to forecast the need to initiate a DLP and provide advance notice to Customer. Utility’s forecast of a DLP shall be communicated to Customer by means of a procedure agreed upon by the Parties providing for notices to be communicated by e-mail, facsimile, or telephone communications between Utility and Customer’s representatives.
 - 5.3 Upon initiation of a DLP, Customer shall take all actions necessary to control its Generating Facility and electrical loads to ensure that the amount of capacity demanded from Utility’s electric system does not exceed the FSL set forth in Section A.2.1, within the time period set forth in Section A.3.1.
 - 5.4 Utility may provide automated notice to initiate or terminate a DLP by closing or opening the contacts of a relay installed in the DLNS provided, installed, operated, and maintained by Utility on Customer’s premises. If an automated DLNS is used, Customer shall use this change in contact position to initiate or suspend the operation of its DLCS and PASS and notify its personnel that a DLP is in effect or has been terminated.
 - 5.5 If Utility determines that its DLNS is not operating correctly to initiate or terminate a DLP, Utility may alternatively contact Customer’s representative by telephone to initiate or terminate a DLP. Should such a manual process be used, Utility and Customer’s representatives shall acknowledge the time the DLP is initiated or terminated and make a record of the notice. If a DLP is initiated by telephone notice, Customer shall manually initiate operation of its DLCS and PASS.
 - 5.6 The Parties shall establish a test protocol and schedule monthly tests as necessary to demonstrate Customer’s ability to receive notifications from Utility’s DLNS and initiate operation of Customer’s DLCS and PASS. Such test periods shall not be considered as DLPs, and shall not count toward any limitations set forth in Section A.3.2.
 - 5.7 Customer shall provide, maintain and operate monitoring and control devices, facilities, and/or operational procedures that will adequately address and satisfy the DLCS requirements of this Agreement.
 - 5.8 To physically assure that Customer has limited its electrical demand to the FSL within the time period established in this Agreement, Customer shall, in addition to its DLCS, install, operate, and maintain a PASS that will automatically physically disconnect all or a portion of Customer’s electrical system from Utility’s electrical system if, for any reason, Customer’s electrical demand exceeds the FSL for more than the time allowed for operation of Customer’s DLCS as set forth in Section A.3.1. If physical separation occurs, Customer may immediately reconnect with Utility’s electric system providing its electrical demand level has been adjusted to a value less than the FSL.
 - 5.9 Utility shall have the right to review, inspect, and approve the design, installation, and function of the Customer’s DLCS and PASS facilities prior to the date set forth in Section **A.1 of this**

Agreement and at any reasonable time during the term of this Agreement. Utility may require Customer to make modifications to its facilities as necessary to comply with the requirements of this Agreement. Utility's review and acceptance of such facilities shall not be construed as confirming or endorsing the Customer's design or as warranting the safety, durability or reliability of such systems. Utility shall not, by reason of such review or lack of review, be responsible for the strength, adequacy, or capabilities of such equipment. Should Customer become aware that its DLCS or PASS facilities are not fully operational, it shall promptly notify Utility and make necessary repairs, adjustments, or corrective actions.

- 5.10 Customer shall provide, at no cost to Utility, a location, dedicated 20 amp, 120 volt (AC) electric circuit, and provisions for a dedicated telephone line, each of which are acceptable to Utility, for the installation and operation of Utility's DLNS facilities.**
- 5.11 If formal rights-of-way or easements are required in, on, under, or over Customer's property or the property of others for the installation of the DLNS, Customer shall acquire or grant such necessary permanent rights-of-way, easements, licenses, or other necessary permission in a form satisfactory to Utility, without cost to Utility. Upon termination of this Agreement in accordance with the terms of Section 4, Utility shall quitclaim or release all easements, rights of way, licenses, or other necessary permission in, on, under, and over Customers property, which are, as reasonably determined by Utility, no longer required by Utility due to the removal of its DLNS.
- 5.12 Customer shall provide reasonable access to its Generating Facility, DLCS, and PASS facilities for Utility personnel, its contractors, or agents as necessary for Utility to perform its duties and exercise its rights under this Agreement and Utility's tariffs.
- 5.13 Customer acknowledges that the correct and reliable operations of the PASS facilities are essential to satisfying the terms of this Agreement. PASS facilities and wiring shall be designed and installed in a manner acceptable to Utility and shall be equipped with locking or sealing devices that will prevent or reveal tampering to defeat the correct operation of the system.
- 5.14 The DLNS, DLCS, and PASS shall not be altered or interfered with at any time by Customer. Utility shall have the right to review and obtain copies of Customer's operations and maintenance records, logs, or other information such as but not limited to, equipment availability, maintenance outages, circuit breaker and relay operations, and unusual events pertaining to Customer's, DLCS, and PASS. In the event Utility determines that the DLNS, DLCS, or PASS has been altered or interfered with by Customer to avoid compliance with the terms of the Agreement, Utility may terminate this Agreement and seek damages from Customer pursuant to Section 7.2 herein. In the event of termination pursuant to this Section 5.14, Customer's obligations under this Agreement, including its obligation to limit its electrical demand during DLPs initiated by Utility, shall continue until such time as Utility is able to make alternate provisions for operating those portions of Utilities electric system directly affected by the absence of the DUF, in a safe and reliable manner.
- 5.15 Notwithstanding any other provision of this Agreement, as provided in its electric service tariffs and rules, Utility may limit or disconnect or require the disconnection of the electric service Customer receives from Utility's electric system at any time, with or without notice, in the event of an emergency or to correct unsafe operating conditions. Utility may also limit or disconnect or require the disconnection of Customer's electric service from Utility's electric system upon the provision of reasonable written notice: 1) to allow for routine maintenance, repairs or modifications to Utility's electric system or DLNS; or, 2) upon Utility's determination that Customer's DLCS or PASS is not in compliance with the terms or intent of this Agreement. Should Customer's electrical service need to be limited or curtailed to effect the terms and conditions of this Agreement, the Parties shall cooperate in good faith to minimize the duration and impact of such limitation.
6. SCHEDULED OUTAGES
- 6.1 Customer may request and schedule the number of Scheduled Outage Days set forth in Section A.4 during each Operating Year of this Agreement. If the term of this Agreement provides for the occurrence of a partial (less than 12 month) Operating Year, the allowance for Scheduled Outage Days shall be prorated based on the number of months this agreement is in effect.

- 6.2 A Scheduled Outage Day shall be effective only upon Utility’s acceptance and consent. Utility shall not be obligated to consent to a Scheduled Outage Day when Utility reasonably forecasts that a DLP may be necessary on the day requested by Customer. Utility shall not unreasonably withhold its consent to Customer’s request for a Scheduled Outage Day.
- 6.3 Scheduled Outage Days shall be scheduled in whole day increments using a procedure to be designated by Utility providing for requests and consents to be exchanged by e-mail, facsimile, or telephone communications between Utility and Customer’s representatives.
7. PAYMENT OF DEFERRAL CREDITS
- 7.1 Deferral Payments shall be based upon an annual value negotiated by and between the Parties. Utility shall pay Deferral Credits to Customer in accordance with the amounts and Payment Schedule set forth in Appendix E.
- 7.2 Deferral Payments shall be divided into equal monthly payments for the term of the Demand Limitation Exposure Period, and paid “in arrears” upon completion of each month of Customer’s satisfactory performance. Payments may be suspended if Customer fails to limit its demand to FSL during any DLP. “Unearned” payments will be forfeited if it is determined that Customer has intentionally breached terms of the Agreement.
- 7.3 Unless otherwise agreed in writing by the Parties, any payment due under this Agreement shall be satisfied by Utility issuing a check to Customer. Utility reserves the right to offset any amount owed to Customer under the terms of this Agreement toward any delinquent amounts due to Utility from Customer for the electric service received at the electric service account location identified in this Agreement.
- 7.4 Deferral Payment obligations shall be prorated on a daily basis in the event of early termination of this Agreement.
8. DEFAULTS AND REMEDIES
- 8.1 If either Party breaches its material obligations under this Agreement, such breach shall constitute an event of default. If any Party defaults under this Agreement, the other Party may terminate this Agreement; provided that prior to such termination the other Party must provide the defaulting Party with written notice stating: (i) the Party’s intent to terminate; (ii) the date of such intended termination; (iii) the specific grounds for termination; (iv) specific actions which the defaulting Party must take to cure the default, if any; and (v) a reasonable period of time, which shall not be less than ten (10) calendar days, within which the defaulting Party may take action to cure the default and avoid termination, provided there is any action which can be taken to cure the default. The pendency of any dispute resolution procedure pursuant to Section 11 with regard to any separate dispute(s) shall not limit the right to terminate this Agreement under the terms of Section 4.
- 8.2 If Customer intentionally breaches its obligation to limit its electrical demand to the FSL established in Section A.2.1 during any DLP initiated by Utility, then the resulting damages shall be calculated to include any cost associated with the accelerated construction of facilities required in Utility’s reasonable discretion to reliably and safely provide service to all customers on the affected portions of Utility’s electrical system (e.g., any cost of overtime hours for Utility’s own resources, additional contract personnel, additional payments to contractors for expedited delivery of equipment and materials and premiums paid, if any, or to obtain necessary rights of way or permits). Utility selection of any facilities contemplated by this Section 8.2 shall be based on good utility practices, including, but not limited to, its standard safety practices, its material and equipment specifications, its established design criteria and construction procedures, its labor agreements and applicable laws and regulations; provided, however, that the Parties understand and agree that if Customer’s failure to limit its electrical demands to the FSL is due solely to an Uncontrollable Force, such failure shall not constitute a default pursuant to this Section 8.2.
- 8.3 Subject to the provisions of Section 11, either Party also shall be entitled to pursue any other legal, equitable or regulatory rights and remedies it may have in response to a default by the other Party.
9. LIABILITY, INSURANCE AND INDEMNITY --To be determined
10. UNCONTROLLABLE FORCES
- For purposes of this Agreement, an “Uncontrollable Force” is any cause or act beyond the reasonable control of a Party and which by the exercise of due diligence by such Party is unable to prevent or overcome. In the event of the occurrence of an Uncontrollable Force which prevents a Party from performing any of its obligations under this Agreement such Party shall (a) promptly notify the other party;

(b) not be entitled to suspend performance of any greater scope or longer duration than is required by the Uncontrollable Force (c) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance hereunder; (d) keep the other Party apprised of such efforts on a continual basis, and (e) provide written notice of the resumption of performance hereunder.

11. DISPUTE RESOLUTION

11.1 Any dispute that cannot be resolved between the Parties shall be settled by means of conference, mediation and/or litigation as provided for herein.

11.2 The first step in the dispute resolution process shall be a conference by which the dispute is referred to a designated officer of each Party for resolution. If those two officers cannot reach an agreement within a reasonable period of time, the Parties may submit the dispute to mediation in accordance with the Commercial Rules of the American Arbitrator Association.

11.3 If the dispute is not resolved by the mediation, the Parties shall submit the dispute to the Commission for final resolution unless the relief sought cannot be awarded by the Commission in which case a Party may proceed to a Superior Court for the State of California, County of Los Angeles.

12. NOTICES

12.1 Any written notice, demand, or request required or authorized in connection with this Agreement (“Notice”) shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:

If to Utility: Company Name
Address: _____
City: _____
Phone: () _____
FAX: () _____

If to Customer: Customer Name
Address: _____
City: _____
Phone: () _____
FAX: () _____

12.2 A Party may change its address for Notices at any time by providing the other Party Notice of the change in accordance with Section 12.1.

12.3 The Parties may also designate operating representatives to conduct the daily communications, which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party’s Notice to the other.

13. ASSIGNMENT

13.1 Customer may assign its rights and delegate its duties under this Agreement with Utility’s written consent.

13.2 Customer shall not voluntarily assign its rights nor delegate its duties under this Agreement without Utility’s written consent. Any assignment or delegation Customer makes without Utility’s written consent shall not be valid. Utility shall not unreasonably withhold its consent to Customer’s assignment of this Agreement.

14. NON-WAIVER

None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

15. GOVERNING LAW, JURISDICTION OF COMMISSION, INCLUSION OF UTILITY’S TARIFF SCHEDULES, DEFINED TERMS

15.1 This Agreement shall be interpreted, governed, and construed under the laws of the State of California as if executed and to be performed wholly within the State of California without giving effect to choice of law provisions that might apply to the law of a different jurisdiction.

15.2 This Agreement shall, at all times, be subject to such changes or modifications by the Commission as it may from time to time direct in the exercise of its jurisdiction.

- 15.3 In addition to the specific terms and conditions provided under this Agreement, Customer’s electric service shall at all times be subject to the terms and conditions set forth in the tariffs applicable to the electric service provided by Utility. Copies of such tariffs are available at www.Utility.com or by written request to Utility and are incorporated into this Agreement by this reference.
- 15.4 Notwithstanding any other provisions of this Agreement, Utility shall have the right to unilaterally file with the Commission, pursuant to the Commission’s rules and regulations, an application for change in rates, charges, classification, service, tariffs or any agreement relating thereto.
- 15.5 When initially capitalized, whether in the singular or in the plural, the terms used herein shall have the meanings assigned to them either in this Agreement or in Utility’s Rule 1.
16. **AMENDMENTS AND MODIFICATION**
This Agreement can only be amended or modified by a written agreement signed by both Parties. Utility shall determine in its sole discretion whether prior Commission approval is required for such amendments or modifications.
17. **ENTIRE AGREEMENT**
This Agreement, including any incorporated tariffs and rules, contains the entire agreement and understanding between the Parties, their agents, and employees as to the subject matter of this Agreement. Each Party also represents that in entering into this Agreement, it has not relied on any promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement or in the incorporated tariffs and rules.
18. **SIGNATURES**
IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

CUSTOMER’S NAME

UTILITY’S NAME

By: _____

By: _____

Name: _____

Name: _____

Title: _____

Title: _____

Date _____

Date: _____

F

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP ATTENDEES

| Name | Title | Org |
|--------------------------|--|--|
| Armstrong, Jim | Program Manager | NStar Electric and Gas |
| Beck, Valerie | Distributed Generation, Energy Division | California Public Utilities Commission |
| Best, Kevin | Principal | Real Energy LC |
| Asgeirsson, Haukur | Supervising Engineer | DTE Energy |
| Bjorge, Bob | Market Development Manager | Solar Turbines |
| Chisti, Ishtiaq | Manager, Project/Product II | SCE |
| Dean, Amber | Attorney | SCE |
| Dossey, Tom | Project Manager, DER | SCE |
| Drolet, Tom | VP International Business | DTE Tech |
| Duggan, Kevin | Manager | Capstone |
| Green, Gary | Dir., Technical Support, Major Customer Div. | SCE |
| Iannucci, Joseph | President | DUA |
| Luke, Robin Ms. | Director | Real Energy |
| Mascarenhas, Sheridan | Distribution Engineer | SCE |
| Montoya, Mike | Senior Attorney | SCE |
| Neal, Russ | Manager, Distribution Engineering | SCE |
| Nimmons, John | President | John Nimmons & Associates |
| O'Connor, Tod | Representative | Solar Turbines |
| Petrill, Ellen | Program Director | E2I |
| Price, Snuller | Partner | E3 |
| Prietto, Tony | Self-Generation Program Manager | Southern California Gas Company |
| Rastler, Dan | Technical Leader, DER Program | EPRI |
| Rawson, Mark | PIER Program: Strategic | CEC |
| Seguin, Rich | Distribution Engineer | DTE Energy |
| Takayesu, Erik | Distribution Engineering Manager | SCE |
| Torpey, James | President | Madison Energy Consultants |
| Wiltsee, George | Manager, Market Devmt, Western US | Ingersoll-Rand Energy Systems |
| Wong, Eric | Manager, Bus. Devmt & Gov. Relations | Cummins Power Generation |

G

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP SUMMARY REPORT

The E2I DER Public/Private Partnership held its second stakeholder workshop at Southern California Edison's CTAC facility on Thursday, October 7, 2004. This report summarizes the workshop discussions, results, and actions.

Twenty-four stakeholders participated in person and three on the phone. The group made unprecedented progress prior to and at the workshop toward developing a successful utility request for proposals for customers to supply distribution services using distributed generation (DG) at their sites. Success is defined as proposals being submitted and accepted, and DG projects being implemented to defer distribution upgrades.

The purpose of the workshop was to:

- Report the working group's recommendations for a successful RFP, based on its July workshop and the work of its two issue groups over the summer
- Report SCE's perspectives and current plans for the RFP
- Move toward consensus on how to approach key issues identified by the working group that remained outstanding
- Record stakeholder perspectives of the value and success of this stakeholder process

In opening remarks, Russ Neal, manager of SCE's distribution engineering, invited stakeholders to continue collaborating toward what is right, and to rise above the "us versus them" approach all too common in similar discussions. He acknowledged that because utilities bring enormous inertia and investment approaches that have worked in the past, it is difficult for new approaches to succeed – but that with work like this stakeholder collaboration, and the commitment to do the right thing, we can move toward a new future. Russ asked the group to imagine the future grid, and how we would design it starting from a clean slate. Distributed generation (DG) has technology characteristics that could provide value to the grid, and may be easier to site than central power stations and transmission and sub-transmission systems. DG could bring higher reliability and security to the grid. Because DG can be modulated, DG may supply VAR support better than capacitors, and may enable intentional islanding that could be an advantage in major grid collapse scenarios. A portfolio including demand response and DG may offer the lowest cost and best safety options.

Russ stressed that while much remains to be learned about the technical design of the future grid, more difficult questions involve the business model necessary to encourage and achieve future grid objectives. Who will own the equipment and access the benefits? How will the costs be covered? These and other business questions are even harder to resolve than the technical problems.

Russ observed that “if we don’t plan, we’ll just replace today’s circuit in kind,” with technology and design that is 50 or 100 years old. To avoid that scenario, SCE is planning a new circuit to be built and operating in 2006, to utilize advanced technology available today, and to serve as a platform to demonstrate new uses and new technologies. He invited stakeholders to offer ideas for the circuit, such as power quality islands, as well as ideas and technologies “as ornaments to hang on this Christmas tree.”

Stakeholder Working Group Report

Stakeholders participated in two issue groups since the first workshop in July, to work through the issues they identified as high priority. SCE staff worked closely as part of each issue group to help reach consensus. Utility solicitations have sometimes neglected to address stakeholders’ perspectives because they have not been sought or articulated. The issue group discussions proved an effective way to do this, and to move the issues forward.

The two groups focused on the following issues. At this workshop, presenters identified each issue; reported on its resolution, if any, by the responsible issue group; and identified questions remaining to be addressed in the workshop (presentation #2).

| Issue Group 1 | |
|----------------------|--|
| 1 | Eligibility for Incentives: Are proposers entitled to deferral incentives under this solicitation also eligible for Self-Generation program incentives? |
| 2 | Physical Assurance Requirement: Is ‘physical assurance’ required every hour of the year, or only during periods when SCE expects to call on the DG resource? |
| 3 | Eligible Resources: Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response? |
| 4 | Alternatives to the RFP Process: Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process? |
| 5 | Additional DG Values: Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response? |
| 6 | Business Model: What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise? |
| Issue Group 2 | |
| 7 | DG Deferral Value: Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG? |
| 8 | Simplification of the Process: How can the solicitation process and/or SCE’s model DG agreement be simplified to reduce all parties’ transactions costs? |
| 9 | Availability of Distribution System Data: What distribution system data will SCE provide to help customers and developers prepare DG proposals that meet its needs? |
| 10 | Tailoring SCE Deferral Agreement to DG Project Realities: Can deferral periods be extended to provide greater value? Can SCE’s Model Agreement be improved to encourage proposals? |
| 11 | Facilitating Interaction between SCE Customers and DG Developers: How will SCE customers be notified & developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise? |

Issues not fully resolved by the issue groups over the summer are listed below. Most were resolved to the stakeholders’ satisfaction just prior to or during the workshop. Results are discussed later in this report.

- #1. Eligibility for incentives
- #2. Physical assurance – how often and how much of the customer’s load
- #7. DG deferral value – supplying a price signal in the RFP so customers and developers could determine whether it was worth the effort to propose
- #8. Simplification of the RFP process and model agreement
- #11. Facilitating interaction between SCE customers and DG developers

SCE’s Plan for Integrating Customer-Operated DG into Distribution Planning

This section highlights key components of SCE’s plan. Presentation #3 provides the full information presented by SCE.

A. SCE’s approach addresses high priority issues with remaining questions as follows:

2. “Physical assurance” will rely on demand limitation.

“Physical assurance” required by the CPUC’s 2003 order will be achieved not by requiring a customer’s DG to operate at critical hours, but by requiring those customers to drop load from the grid if their DG *doesn’t* operate during those hours – i.e., by customers willing to limit demand under agreed conditions, or face automatic disconnection of designated load if they fail to do so. The agreement between customer and utility will be based on a firm service level (lower than full load) selected by the customer that will not be exceeded at those peak times when the utility cannot serve the customer’s full load due to deferring an upgrade or expansion. If the customer’s DG is operating, then it can continue to meet its full load in excess of the firm service level supplied by the utility. The demand limitation periods, when the firm service level caps grid-supplied electricity, will be limited to about 200 to 400 hours per year and 8 to 12 hours on any single day, as agreed between the customer and the utility.

7. DG deferral value (supplying a price signal in the RFP so customers and developers can determine whether it’s worth proposing).

SCE considered this working group request long and hard. SCE ultimately agreed to provide a “market reference price” to guide proposers. This reference price will likely be lower than the utility’s carrying cost of capital for the deferral. The actual price (deferral payment) paid to customers willing to limit demand may be higher or lower than the market reference price, depending on the proposals submitted and selected.

8. Simplification of the RFP process and model agreement

To comply with the CPUC’s 2003 Order, SCE and other California utilities had submitted “Model Agreements” as a starting point for negotiations to acquire DG following a solicitation process. Reconsideration of that process through the collaborative, and working group comments on SCE’s original Model Agreement, caused SCE to substantially rewrite its proposed Agreement. Its new form of Agreement is essentially a different agreement than the original, embodying the “demand limitation” approach described above rather than focusing on physically assuring the performance of customer DG units. Risks are spread more reasonably between customer and utility than was the case with the original agreement.

SCE plans to seek CPUC approval for its new form of Model Agreement. Final terms governing individual transactions between customers and the utility will be based on negotiations, starting with the form of Agreement developed in this stakeholder process.

This is another key point of the process: this will not be a sealed bid process with a “take it or leave it” result. Since any final agreement will be between SCE and its customer, SCE wants its customer to be satisfied with the process and the end result, and recognizes that negotiations may lead to substantive changes in individual final Agreements compared with the Model Agreement developed here. For example, if SCE needs more capacity to defer the distribution upgrade, proposing customers may be asked if they are willing to increase the demand limitation offered in return for a higher price.

The collaborative discussed the RFP process in detail. It sketched out a simplified, two-step process in which customers and developers indicate interest in further information, sign a non-disclosure agreement, then after some screening for vendors, receive the full request for proposal package with detailed information including location, market reference price, and size of proposed deferment. SCE agreed to refine this process and share its conclusions with the working group for comment before finalizing.

9. Customer-vendor (developer, manufacturer, or consultant) interaction

Developers and equipment vendors desire as much support as possible from SCE to connect them with SCE customers interested in hosting projects. SCE agreed to facilitate interactions as follows:

- It will encourage customers located in areas targeted for deferral to participate in the RFP process.
- It will share with prospective proposers contact information for customers who respond to the first phase of the RFP process and agree to be contacted
- It will hold customer-vendor “fairs” in or near the areas targeted for deferral.

B. RFP Timing

- SCE will delay issuing its first RFP from the expected fall 2004 release to spring 2005, due to changes in its distribution planning process and its desire to secure CPUC approval for changes in the Model Agreement that have resulted from this stakeholder process.
- Delaying the RFP will preclude its use for 2005-2006 projects, so SCE proposes “soft start” activities to occur in parallel with its formal solicitation during those years. SCE will contact customers with existing DG in regions where demand limitation has value and will pilot agreements and installations to test concepts, develop procedures, and gain experience. This may be an opportunity for continued stakeholder involvement to collaborate on innovative solutions.
- SCE’s “circuit of the future” activities may also offer opportunities for stakeholder involvement.

The Unresolved Issue: Self-Generation Incentive Program (SGIP) Eligibility

The SGIP program rules state that SGIP recipients may not be recipients of incentive payments for distribution deferral. The E2I working group suggests a waiver of that exclusion for this pilot project. An issue paper was prepared about this issue and delivered to Mark Rawson, the California Energy Commission’s point person for DER policy. Mark agreed to work the issue within the Energy Commission and possibly the California Public Utilities Commission, and to keep the working group apprised through Ellen Petrill.

What Worked, What Didn’t, What’s Missing

The roundtable to address these questions resulted in the following general comments.

What Worked:

- SCE – willingness to listen and cooperate, hard work and energy of the team, especially Tom Dossey and Stephanie Hamilton
- SCE’s vision—Russ Neal
- E2I project team’s expertise, organization, effort, energy, conference calls
- Stakeholder team--talented, energetic, willing to work
- Opportunity to collaborate to work through issues, better to talk than to shout as adversaries

What Didn’t Work:

- The size of the opportunity – small numbers of MW and customers to be part of the RFP
- “Voting with dots” – may miss some key issues by narrowing the discussion

What’s Missing:

- Final result is missing – we can’t call this a success until we get iron in the ground
- Customers are largely missing from the discussions – more representation would help
- Concrete information about projects (e.g., which circuits, size of deferrals needed, etc.)
- Developing DG to serve distribution system needs, not just customer needs

Actions:

1. Mark Rawson to work the SGIP eligibility issue within the California Energy Commission and possibly the California Public Utilities Commission, and keep the E2I working group apprised through Ellen Petrill.
2. Ellen Petrill to send working group the three issue papers prepared to address major issues identified by this group.
3. Tom Dossey to refine the RFP process and share with the working group for final input.
4. Working group to review Model Agreement and send comments to Ellen Petrill and Tom Dossey by October 15 (two have done this.)

H

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP PRESENTATIONS

The presentations can be found on the EPRI website at the following link <http://www.epri.com/der-ppp/index.html>. This link provides the reports of the EPRI DER Public/Private Partnership. Click on [pilot project](#) for presentations from the workshops and other materials from the pilot project.