CONSULTANT REPORT

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CALIFORNIA ENERGY COMMISSION

Strategic Energy Research

FORGING A CONSENSUS ON INTERCONNECTION REQUIREMENTS IN CALIFORNIA (FOCUS)

Gray Davis, *Governor*

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Legal Notice

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Commission), annually awards up to $62 million through the Year 2001 to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Environmentally-Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Strategic Energy Research.

In 1998, the Commission awarded approximately $17 million to 39 separate transition RD&D projects covering the five PIER subject areas. These projects were selected to preserve the benefits of the most promising ongoing public interest RD&D efforts conducted by investor-owned utilities prior to the onset of electricity restructuring.

What follows is the final report for the effort entitled “Forging a Consensus on Interconnection Requirements in California (FOCUS)”, Contract Number 700-99-010, conducted by prime contractor ONSITE SYCOM Energy Corporation and the FOCUS team of subcontractors including Reflective Energies, Inc., Endecon, Resource Catalysts, and Michael Edds. This project contributes to the PIER Strategic Energy Research program.

For more information on the PIER Program, please visit the Commission's Web site at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.

Executive Summary

Introduction

Today, California does not generate enough electricity to meet growing demand. This has caused an energy crisis in the state. The Commission had begun to search for ways to accelerate proliferation of Distributed Generation[1] (DG) [2] when it issued the Order Instituting Investigation (OII) November 3, 1999 to identify barriers to the development of DG technologies and to develop recommendations to remove those barriers. The Commission accepted the task of developing rules and bringing its recommendations to the California Public Utilities Commission (CPUC) for discussion and possible adoption. Under the OII, the Commission was to explore barriers to DG in the areas of Interconnection and permit streamlining. The FOCUS technical support contract that is the subject of this report was signed to help the Commission fulfill its OII obligations.

The FOCUS team successfully completed 14 Interconnection objectives and 3 CEQA review and permit streamlining objectives. Each of these 17 objectives produced outcomes and recommendations. The objectives and outcomes are outlined below.

Objectives

Interconnection Objectives (1 through 14):

- Objective-1: Facilitate consensus on the technical issues of Interconnection.
- Objective-2: Make Interconnection a single uniform process which is internally consistent and predictable statewide.
- Objective-3: Provide a method of Simplified Interconnection.
- Objective-4: Explore the role of advanced communications and metering for Interconnection scheduling and dispatch.
- Objective-5: Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs).
- Objective-6: Lower the cost of Interconnection.
- Objective-7: Fulfill the need for interim standards.
- Objective-8: Address safety issues.
- Objective-9: Define the scope and feasibility of Type Testing.
- Objective-10: Accelerate the adoption of DG by training and informing government agencies.
- Objective-11: Define the scope of technologies covered by Rule 21.
- Objective-12: Make changes to utility tariffs proceeding from Interconnection rules.
- Objective-13: Facilitate Interconnection of small units.
- Objective-14: Eliminate utility discretion of study fees.

CEQA Review and Permit Streamlining Objectives (1e through 3e):

- Objective-1e: Identify barriers to DG in the CEQA Review and Land-Use Approval process and produce recommendations for removing or mitigating those barriers.
- Objective-2e: Identify barriers to DG in the building permitting process and produce recommendations for removing or mitigating those barriers.
- Objective-3e: Identify barriers to DG in the air permitting process and produce recommendations for removing or mitigating those barriers.

Outcomes

Interconnection Outcomes

Objective-1: Facilitate consensus on the technical issues of Interconnection.

Outcomes:

- Section 4, Appendix A and Appendix B of the Revised Rule 21 (see Attachment A) covers all technical work of the workgroup.
- The technical work achieved 100 percent consensus in both the technical subgroup and the full workgroup.
- The non-technical work (Sections 1-3 and 5-7) of the Revised Rule 21 achieved consensus on every point of the document except one—the question of indemnity.

Objective-2: Make Interconnection a single uniform process which is internally consistent and predictable statewide.

Outcomes:

- With adoption of the Revised Rule 21, the CPUC requires that each of the three investor-owned Electrical Corporations (ECs) replace its old Rule 21 with the Revised Rule 21.
- DG Developers have a greater degree of certainty under the Revised Rule 21 with respect to how much it will cost and how much time it will take for the utility to complete an Interconnection study. The study itself will contain the information necessary for a firm estimate of total Interconnection project cost.
- ECs under CPUC jurisdiction are filing Advice Letters to implement the change to the Revised Rule 21.
- Applicants are using the new Application form.
- No certification process has been established.
- No interim certification process has been established.

Objective-3: Provide a method of Simplified Interconnection.

Outcomes:

- The Technical subcommittee devised an Initial Review Process.
- The Technical subcommittee drafted a Certification Process.

Objective-4: Explore the role of advanced communications and metering for Interconnection scheduling and dispatch.

Outcomes:

- Workgroup participants were interested only in establishing the very minimum metering necessary to provide information to the EC and the California Independent System Operator (CAL-ISO).
- Consensus position was to allow Net Generation Metering, but only when necessary and when no other source of information would suffice.
- Minimum threshold of 1MW established for Telemetering; minimum reduced to 250kW for Generating Facilities interconnected to a Distribution System operating at a voltage below 10kV.
- The Workgroup did not discuss bi-directional flow of electricity, or advanced digital communications.

Objective-5: Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs).

Outcomes:

- The Revised Rule 21 contains only PBIRs.
- The PBIRs are embedded in Section 4 and Appendix A, the Initial Review Process (IRP) of the Revised Rule 21 (see Attachment A).

Objective-6: Lower the cost of Interconnection.

Outcomes:

- The workgroup came to consensus on fees for Interconnection studies. (See Objective – 14).
- If the utility needs additional study on a more complicated Interconnection, the workgroup agreed that it should notify the Applicant within the initial review period of the cost and time needed.
- The workgroup came to consensus on 10 days for the utility to acknowledge receipt of the application for Interconnection and to say whether it was correct and complete.
- The Revised Rule 21 gives developers with multiple installations or other non-standard Interconnections the ability to negotiate fees with the utility.
- All the foregoing add certainty to the process and help reduce the carrying cost and the study fee cost of Interconnection.
- DG units passing the IRP will be spared additional hardware costs that could increase total installed cost per kW by $200 to $330 (10 percent to 33 percent, for projects ranging from $1000 to $2000/kW in total installed cost).
- Documentation of empirical costs and cost reductions are left to subsequent study.

Objective-7: Fulfill the need for interim standards.

Outcomes:

- Some of the technical details in Section 4 and Appendix B of Attachment A may be superceded by an IEEE standard.
- Other changes may be recommended to Revised Rule 21 in the future.
- Technically, Revised Rule 21 is a tariff, not a standard.

Objective-8: Address safety issues.

Outcomes:

- All PBIRs are safety limits; Section 4.3 of the Revised Rule 21, Appendix A and B all cover technical safety requirements (see Attachment A).
- Purpose of Rule 21 is to maintain safety during Interconnection.

Objective-9: Define the scope and feasibility of Type Testing.

Outcomes:

- The scope was broadened by the Testing and Certification subgroup to include Production Testing, Commissioning Testing and Periodic Testing as well as Type Testing. (See Glossary for definitions.)
- The workgroup used existing testing procedures, especially UL1741 and IEEE929, whenever possible.
- Certification of equipment was included. Equipment certified for Interconnection is defined as "Equipment tested and approved (e.g. listed) by an accredited, nationally recognized testing laboratory (NRTL) as having met both the Type Testing and Production Testing requirements ..."

Objective-10: Accelerate the adoption of DG by training and informing government agencies.

Outcomes:

- All of the workgroup documents, including the Revised Rule 21, are available on the Energy Commission's website (www.energy.ca.gov/documents).
- No formal outreach or training was conducted.

Objective-11: Define the scope of technologies covered by Rule 21.

Outcomes:

- Both the technical and non-technical subgroups agreed that the discussions should not be limited by prime mover technology type, prime mover fuel or by generator size (in kW). Instead, the scope was limited electrically and jurisdictionally by stating that the rule applies only to generation on the distribution system level.
- The scope of Interconnection technologies is defined within categories of generators: inverters, synchronous generators and induction generators.

Objective-12: Make changes to utility tariffs proceeding from Interconnection rules.

Outcomes:

- The workgroup made changes to utility tariff Rule 21.
- The workgroup chose to limit itself to Rule 21 and to leave changes to standby and rate tariffs to the CPUC Energy Subcommittee.

Objective-13: Facilitate Interconnection of small units.

Outcomes:

- The IRP is designed specifically for smaller certified units to be interconnected with a minimum of time and expense.
- The IRP does not differentiate units according to kW sizing to avoid putting arbitrary limitations into the rule.

Objective-14: Eliminate utility discretion of study fees.

Outcomes:

- Study fees are set at $400 pre-contract initial review, $600 supplemental review, $400 post-contract review; fees are minimum $800 for projects not requiring supplemental review and a maximum of $1400 for all projects requiring supplemental review but not requiring detailed studies.
- Fees for detailed review are variable.
- An Applicant has a much clearer idea going into an Interconnection project how much it will cost and how long it will take.

CEQA Review and Permit Streamlining Outcomes

Objective-1e: Identify barriers to DG in the CEQA Review and Land-Use Approval process and produce recommendations for removing or mitigating those barriers.

Outcomes:

- Some DG is already exempt from CEQA.
- For non-exempt DG, review time can be reduced from one year to six months for DG which avoids or mitigates significant effects on the environment.
- CEQA Review / Land-Use barriers and solutions identified.

Objective-2e: Identify barriers to DG in the building permitting process and produce recommendations for removing or mitigating those barriers.

Outcomes:

- DG projects are exempt from building permits if the entity conducting the project has been specifically exempted in the State Building Standards Code or Government Code of Regulations.
- All others must obtain permits, and streamlining is a necessity.
- Building permitting barriers and solutions identified.

Objective-3e: Identify barriers to DG in the air permitting process and produce recommendations for removing or mitigating those barriers.

Outcomes:

- DG equipment which does not emit air pollutants does not need to obtain air permits.
- DG equipment with air emissions below specific permitting thresholds (set by the district) are exempt from air permitting. For example, fuel cells do not need air permits when they are installed in South Coast AQMD.
- Some energy storage batteries emit toxic air contaminants and are not exempt from obtaining air permits.
- The FOCUS team identified Air Permitting barriers and solutions.

Conclusions

All of the objectives in this project were successfully completed. Some produced outcomes which were different than what was originally intended, but these changes complemented the overall work process better than the expected outcomes could have done.

DG can and should be a key component in the future of California energy supply. The OII Interconnection and permit streamlining efforts delivered recommendations the CPUC which can hasten the day when DG becomes a more significant part of the solution to California's energy needs. The Interconnection effort delivered a Revised Rule 21 which implements all of its recommendations as a tariff. It was rapidly adopted by the CPUC both in its initial and final forms.

Recommendations

A post-implementation workgroup should be formed to further the work on Interconnection. This workgroup could ensure the success of the Revised Rule 21. Testing and Certification work, particularly, needs further advancement before any DG unit can be considered for Simplified Interconnection. The IRP, the Agreement form and the Application all need to be tested in the real world. DG systems operating in the field should be monitored to see how they are interacting with the distribution system. These data should be analyzed and the results communicated to the post-implementation working group, to the utility, to the DG developer and Applicant. Changes necessitated by real experience of using the Revised Rule 21 need to be made to ensure the relevance and usefulness of the Rule. Finally, the effort to implement Chapter 741 of the Statutes of 2000 needs to carry out its mandate to make air permitting more efficient for all DG.

Benefits to California

The FOCUS team successfully fulfilled the technical and economic performance objectives laid out in its workstatement. The team achieved 99 percent consensus on non-technical issues and 100 percent consensus on technical issues.

The FOCUS team outperformed its own tactical objectives as well, as shown in the table below.

Table 1. Tactical Performance

Tactical Performance	w/o Contractor	w/ Contractor	% Gain
Estimated Consensus PBIRs[3]	18	48	167%
Actual Consensus PBIRs	18	50	177%
Estimated Cost-Critical Policy Issues	5	7	40%
Actual Cost-Critical Policy Issues[4]	5	9	55%

The purpose of this FOCUS project was "to produce recommendations on interconnection which if implemented will lead to interconnection cost reduction."[5] The team's strategic performance is measured in terms of cost reduction over seven years, starting in year 2000. Scenario-0 is the basecase[6] year 2000, the cost of interconnection prior to workgroup activity, unadjusted for future technological cost reductions. Scenario-1 is the cost of interconnection in 2006 adjusted for technological advancement, but with no other changes to interconnection rules. Scenario-2 is the level of cost savings achieved in 2006 based on the work completed so far (the CPUC-adopted Revised Rule 21). Scenario-3 is the estimated interconnection cost in 2006 with all recommendations of Revised Rule 21 and the additional recommendations in this report having been enacted.

Table 2. Cost by Size for Interconnecting DG Systems

	2000	2006	2006	2006	2006	2006
Strategic Performance[7]	Unadjusted Scenario-0	Adjusted Scenario-1	Scenario-2	Scenario-3	*Expected*[8] *% Gain*	*Actual*[9] *% Gain*
Less than 200kW	$125	$93	$73.50	$54	41.9%	41.2%
From 200kW – 1MW	$ 95	$69	$53.50	$38	44.9%	43.7%
Greater than 1MW, $/kW	$ 33	$28	$24.50	$21	25.0%	25.8%

Abstract

The effort entitled Forging Consensus on Interconnection Requirements in California (FOCUS) was funded by the California Energy Commission (Commission) with Public Interest Energy Research (PIER) Strategic Energy program funds. The FOCUS team, including ONSITE SYCOM, Reflective Energies, Michael Edds, and Endecon, worked with Commission staff to lead and support a series of technical workshops that included representatives from all California investor-owned utilities, several municipal utilities, manufacturers of Distributed Generation (DG) technologies, developers of DG projects, the CPUC and others. The purpose of the meetings was to investigate existing barriers to DG Interconnection and DG siting and permitting, and to make recommendations to the CPUC on removing these barriers. The Interconnection workgroup met from January through March to produce a Revised Rule 21 and an initial set of recommendations. The workgroup met again in July and August to complete work on several unfinished issues and to produce a final Revised Rule 21 and a final set of recommendations. The CPUC adopted the initial (Decision 00-11-001, November 2, 2000) and final Revised Rule 21 (Decision 00-12-037 December 21, 2000) and both sets of recommendations. The CEQA Review and Permit Streamlining recommendations have been approved by the Commission and sent to the CPUC,10 as required by the OII.

By adopting the new Rule 21, California replaced three outdated non-standard Rules 21, one each for the Investor-Owned Utilities (IOUs), with one uniform Revised Rule 21. The new Rule removes significant barriers to safe, cost-effective Interconnection of DG in California. More research is needed to determine actual effects of interconnecting DG, and to aid the process of DG certification for Interconnection. The CEQA Review and Permit Streamlining work has not yet been implemented by local jurisdictions nor adopted by the CPUC. More funding is needed to implement the recommendations at the local level. Nonetheless, this work advances the body of knowledge of DG permitting by clarifying where barriers exist and by recommending some practical steps to mitigating those barriers.

Key Words: Distributed Generation, DG, Interconnection, Air Permit Streamlining, Building Permit Streamlining, California Environmental Quality Act, CEQA

1.0 Introduction

Prior to the California electricity market restructuring in 1998, independent power producers could only build and connect plants to the grid if they were Qualifying Facilities (QFs) as defined by the Public Utilities Regulatory Policies Act (PURPA) of 1978. Historically, Interconnection Requirements (IRs) of utilities were developed in response to PURPA, which allowed QFs to interconnect with the grid. Most of the QF-supplied power (on a MW basis), is concentrated in a small number of large facilities.[11] Each electric utility developed a Rule 21 to handle Interconnection of QFs in their service territory, aimed primarily at installation of facilities over 50 MW. The utilities assumed that Interconnection of each facility would have to be custom-engineered. The primary consideration of the utilities' Interconnection Requirements (IRs) was the safety and reliability of the Interconnection for protection of utility personnel and equipment. Little consideration was given to reducing Interconnection cost, complexity or time frame. Moreover, the IRs were implemented differently by each utility.

After restructuring

With passage of AB 1890, California's electricity restructuring legislation, the regulated utilities sold most of their generation to private companies, unregulated by the CPUC.[12] The requirement for QF status was eliminated, opening up the power generation business to those who want DG to serve domestic loads. DG manufacturers produced DG products to suit loads of all sizes, from less than 1 kW to hundreds of megawatts. The locations where small DG could potentially apply far outnumbers the locations where large DG applies, so there was a new focus on the market for DG less than 1 MW in size.

Barriers

The old market rules became serious barriers to Interconnection of small DG. IRs of the host utility were burdensome and costly to implement, for small projects and often made otherwise cost-effective projects economically infeasible. Developers who wished to install DG in more than one utility's service territory were frustrated by the lack consistency between the IRs. Application fees and study costs varied widely and were impossible to predict. Not all utilities had a well-developed and consistent procedure for handling applications to connect. Many of these problems were inherent in how the IRs were created.

The Order Instituting Investigation (OII)

Observing the relatively slow entry into the new market, some regulatory and industry groups felt until the barriers to DG were defined and removed, DG could not take advantage of the new opportunities. Some analyses indicated that cost of Interconnection and long and costly environmental permitting procedures were acting as barriers to DG.[13] For these reasons the California Alliance for Distributed Energy Resources (CADER) asked the CPUC to open an Order Instituting Rulemaking (OIR) on DG to explore what barriers existed and how they might be removed. The OIR on Distributed Generation and Distribution Competition, R.98-12-015, was followed in October 1999 by R.99-10-025, which dealt exclusively with DG. The latter Rulemaking and the adoption of the Decision on the OIR (D.99-10-065) provided a procedural roadmap for addressing issues related to DG. The decision was the result of collaborative efforts among the CPUC, the Energy Commission, and the Electricity Oversight Board. On November 3, 1999 the Energy Commission issued an OII to identify barriers to the development of DG technologies by utility Interconnection and other rules, and then to develop, if possible, recommendations to remove those barriers. The Commission was assigned the task of developing these rules and subsequently bringing its recommendations to the CPUC for discussion and possible adoption. Through the OII the Commission was also obligated to consider whether local government agencies could use a streamlined process to address any CEQA issues in reviewing DG facilities.

1.1 Background and Overview

The FOCUS project was designed to support the Commission's OII effort and specifically to "identify barriers to the development of [DG] technologies" in the areas of Interconnection and environmental permitting. Recommendations both on Interconnection and CEQA review were to be submitted to the CPUC and interested parties during summer 2000. The FOCUS contract became the vehicle to provide technical support to these processes.

1.1.1 Interconnection

On January 12, the full Commission gave approval to the FOCUS-Interconnection project and the FOCUS team took on the tasks needed to fulfill its contract and to give full support to the needs of the FOCUS-Interconnection Workgroup (Workgroup) and the CEQA Review effort (CEQA Workshop). The Interconnection issue required, and was given, more effort and emphasis than the CEQA effort. The Interconnection group began meeting in January and continued to meet through March; some additional smaller group meetings were held in April through June. When the Commission's June report was produced, there were still some outstanding issues to be resolved. These were addressed during additional meetings in August and September. The Commission's October supplemental report describes the outcome of this additional work.

The Workgroup consisted of more than 100 people who attended the workgroup meetings during its initial meetings (January to June). Workgroup members came from the three investor-owned utilities in California, from municipal utilities (including Sacramento Municipal Utility District, Los Angeles Department of Water and Power, Riverside Public Utilities, City of Redding, Hetch Hetchy Water and Power and the California Municipal Utilities Association), from manufacturers (including Honeywell, Capstone and Elektryon), from developers and energy companies (including Enron and NewEnergy), from the Office of Ratepayer Advocates, from construction and solar energy developers (Solar Development Cooperative and M&H Property management), and representatives of cogenerators (Cogeneration Association of California, Energy Producers and User's Coalition). A number of other organizations—public, private and non-governmental organizations—audited the process by email and telephone conference.

1.1.2 CEQA Review and Permit Streamlining

Between the time the OII was issued and the April Workshop was held, the Commission decided to expand the scope of the permit streamlining effort to include air and building permitting. The Commission wanted to involve as many people as possible in the discussion to give full treatment to the whole gamut of DG permitting requirements. In addition to the one hundred-forty people on the CPUC service list, twelve-hundred state and local governmental entities were notified of the Public Hearing on CEQA review in April 2000. The Commission, the Air Resources Board ARB, the California Environmental Protection Agency, the Natural Resources Defense Council, and from private industry gave presentations. The event was covered by internet broadcast. Afterwards, Commission staff prepared the Workshop Report mentioned above.[14] Copies of the Workshop Report were mailed to the CPUC, to everyone who attended the workshop, to all who were participating in the CPUC's DG proceeding, and to local jurisdictions, including pollution control officers, planning managers and permit engineers for each California air district, and planning and/or community development directors and the chief building officials of all California cities and counties.

The Workshop Report mailings to cities and counties included a survey to collect feedback about current DG permitting activities and local government interest in receiving technical assistance or training to facilitate DG permitting in the future. Different surveys were sent to city and county planning directors and to city and county building officials. By October 17, 2000, 143 local jurisdictions had responded, including 4 towns, 18 counties and 121 cities. The Planning and Development survey, for example, included a matrix of DG equipment types (fuel cells, diesel generator, batteries, photovoltaics (PV) and natural gas-fired turbines or cogeneration) and zoning designations and asked respondents to mark whether a use permit was required for each. The form also asked about whether the agency had ever received a DG permit request and what kind of information might help the agency make a permitting decision. The Building survey was similar.[15]

On September 7, 2000, a Committee Hearing was held to gather public comment on the Workshop report, the surveys, and any other input from participants on CEQA review or building and air permitting. The public comments and all written comments, along with Committee recommendations to the full Commission, were written into the Siting Committee's CEQA Review and Permit Streamlining report.[16]

1.2 Project Objectives[17]

Order Instituting Investigation number 99-1103-11 issued November 3, 1999 states: "The main objective of this investigation is to identify barriers to the development of DG technologies by utility Interconnection rules and air quality management district rules for some DG technologies. The results of this investigation are expected to be a series of recommended changes to the rules of the CPUC, publicly-owned utilities, and air quality management districts." The FOCUS team molded this overall OII objective into a series of discrete objectives, then led the workgroups toward accomplishment of these.

Objective 1 supports the workgroup process; Objectives 2 through 14 support the Interconnection process. The three permit streamlining objectives identify permitting barriers and to make recommendations on how to mitigate or remove those barriers. The first objective covers the California Environmental Quality Act (CEQA) Review, the second covers building permitting and the third covers air permitting.

1.2.1 Interconnection

The objectives for this project are as follows:[18]

1. Facilitate consensus on the technical issues of Interconnection. [OII, Workstatement]
2. Make Interconnection a single uniform process which is internally consistent and predictable statewide. [Workstatement, Workgroup]
3. Provide a method of Simplified Interconnection. [Workstatement]
4. Explore the role of advanced communications and metering for Interconnection scheduling and dispatch. [OII, Workstatement]
5. Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs). [Workstatement]
6. Lower the cost of Interconnection. [Workstatement]
7. Fulfill the need for interim standards. [OII]
8. Address safety issues. [OII]
9. Define the scope and feasibility of type testing. [OII]
10. Accelerate the adoption of DG by training and informing government agencies. [OII]
11. Define the scope of technologies covered by the Rule 21. [OII]
12. Make changes to utility tariffs proceeding from Interconnection rules. [OII]
13. Facilitate Interconnection of small units. [Workgroup]
14. Eliminate utility discretion of study fees. [Workgroup]

In addition to working with the workgroup to produce outcomes and recommendations for these objectives, the FOCUS team also provided centralized work planning and organization, drafting of work products, communications between workgroups, oversight through a Commission-appointed Advisory Board, and coordination among stakeholders.

1.2.2 CEQA Review and Permit Streamlining

There were three primary objectives for the CEQA portion of the investigation:[19]

1. Identify barriers and propose solutions to streamline the CEQA Review and Land-Use Approval process.
2. Identify barriers to DG in the building permitting process and produce recommendations for removing or mitigating those barriers.
3. Identify barriers to DG in the air permitting process and produce recommendations for removing or mitigating those barriers.

In order to fulfill these objectives, the Siting Committee conducted a public workshop in April 2000 and the staff published the Workshop Report on Distributed Generation: CEQA and Permit Streamlining.[20] The staff also surveyed local government planning directors and building officials about their experiences in performing CEQA reviews, issuing permits for DG projects and their need for written guidelines or training to assist them in performing this regulatory work in a more timely manner. The Siting Committee conducted a public hearing in September 2000 to receive feedback on the Workshop Report and to present findings from the staff s local government surveys. This Committee Report summarizes the key findings from the two public meetings, written comments survey responses and staff research. Upon approval by the full Commission it will be forwarded to the CPUC for inclusion in the CPUC's DG proceedings.

1.3 Report Organization

The Interconnection and Permit Streamlining sections of this paper in Sections 2 and 3 respectively will be structured identically, with a description of Project Approach, then a description of Project Outcomes, followed by Conclusions and Recommendations. The Interconnection effort was more time- and cost-intensive and will get more detailed reportage.

The final section will contain Conclusions, Recommendations and Benefits analysis covering both Interconnection and Permit Streamlining issues.

2.0 Interconnection Project

2.1 Interconnection Project Approach

The overall goal of the workgroup effort was to produce a Revised Rule 21 that utilities and DG developers and manufacturers could use for practical guidance through the process of Interconnection. The approach taken to achieve this goal was laid out in the OII. "The OII will commence with a workshop process that addresses...topics included in CPUC Decision 99-10-065. ... Formal recommendations on Interconnection rules will be provided to the CPUC and other entities in a manner that accommodates the CPUC's OIR schedule. Unless prevented by unforeseen scheduling changes, formal recommendations are expected to be submitted in mid-June 2000."[21] The FOCUS contract was to give technical support to the Commission staff to run these workshops. The initial FOCUS contract covered meetings through June; when the Commission asked for supplementary meetings during the summer to resolve contentious issues, or important issues which had to be put aside because of the tight timeframe, a contract augmentation was filed and accepted. The contracts called for twenty meetings; twenty-one meetings were held, including 12 large group meetings, 5 technical group meetings, 3 Commission Hearings, and an Advisory Committee meeting.[22]

The Texas and New York Interconnection processes and the existing Rules 21 of the three IOUs and associated utility guides provided raw material for this work. Ongoing standards efforts by the IEEE were integrated into the process.

Objectives 1 through 6 came from the workstatement; Objectives 7 through 12 come from the OII; Objectives 13 and 14 come from the workgroup. Objective-1 and Objective-4 were contained in both the workstatement and the OII objective list; Objective-2 was in the workstatement and also was expressed by the workgroup. Because the objectives came from the workstatement, the OII and the workgroup, some precedence of conflicting objectives had to be established. The workstatement contained language that allowed the workstatement objectives to be modified at the discretion of Commission staff; the staff worked closely with the workgroup to transmit group desires into the FOCUS effort. That language prevented the workstatement from mandating work deemed by the workgroup to be irrelevant, and conversely allowed the workgroup to dictate priorities to the workstatement and the OII. In fact, the objectives of the workstatement and the OII were deemed useful by the workgroup, though not always in the proportion originally accorded them. Changes in objective priority are noted in section 2.2 below.

Primary overall direction of the workgroup was provided by the Commission through Scott Tomashefsky. The Energy Commission's Contract Manager, Jon D. Edwards managed work approval and modification of workstatement tasks. The FOCUS team facilitated the group effort by taking on key roles in the discussions. Bill Brooks chaired the Technical group, Mike Edds took the lead in formulating the Initial Review Process and Chuck Whitaker chaired the Testing and Certification committee. Edan Prabhu took the lead in organizing a glossary and making sure it was applied consistently within all the work products of the Workgroup. Cris Cooley lead process management and project logistics (Task 2.2), setting up the email distribution list and capturing all comments and discussion in the ever-changing Revised Rule 21 working draft. From these positions, the FOCUS team worked within both Technical and Non-technical workgroups to produce outcomes and recommendations for all the objectives.

2.2 Interconnection Project Outcomes

The Interconnection workgroup succeeded in producing a Revised Rule 21[23] that was adopted by the CPUC.[24] The document contains 99 percent consensus language (see section 2.2.1 below for a description of the non-consensus item.) This section describes how the objectives of the workstatement, OII and the workgroup were resolved and what specific outcomes they produced.

2.2.1 Context and Goal – Objective-1 and Objective-2

2.2.1.1 Objectives

Objective-1 (Facilitate consensus on the technical issues of Interconnection) and Objective-2 (Make Interconnection a single uniform process which is internally consistent and predictable statewide) served as the context and goal, respectively, for the workstatement. Consensus was the basis for all the other objectives and the reason the workgroup met. All the other Interconnection objectives strove to create a consistent and uniform process in California.

As additional support for Objectives 1 and 2, and to fulfill it Task 2.1, the FOCUS team worked with the Contract Manager and Commission OII staff to form an Advisory Committee. The FOCUS team submitted a list of potential AC appointees to the Commission and received approval on the choices. The Advisory Committee consisted of Mark Skowronski of Honeywell, Dave Townley of NewEnergy, Tom Dossey of SCE, and Wayne Raffesberger of Coast Intelligen. The members of the AC were workshop participants, so they were already familiar with the context and goals of the workgroup and were in a position to be able to judge the progress on Objective-1 and Objective-2. The group met with the FOCUS team on March 28th at the San Francisco offices of PG&E.

Each Committee member was asked to provide candid feedback on the work being done by subgroups in each of the following areas: 1) Non-Technical (contractual, timing and transactional issues); 2) Technical issues (establishing the requirements for simplified Interconnection); 3) Initial Review Process (to evaluate whether a prospective Distributed Generator may qualify for Simplified Interconnection); 4) Testing and Certification process (to set up a process where independently tested equipment and systems may be installed as DG with minimal review).

Committee members agreed that the workshops were conducted in an open manner. They also felt that all participants were generally working towards resolution of issues, while safeguarding the interests of their constituencies. Discussions were adjudged frank and honest. The deliberations helped each of the stakeholder interests appreciate the interest of the other parties and that understanding has helped towards obtaining resolution. It was felt that the process had come a long way from a year previous, when there was some mistrust and suspicion. It was also felt that the timetable was aggressive and perhaps a better process would result if the timetable was a few months longer. After some discussion, the group concluded that perhaps it was good to be aggressive, because if more time was available the process would simply have gone slower. One consequence of the aggressive timetable has been that the process had narrowed down to just those items that are the most pressing barriers to Interconnection for the most likely early entrants, with several issues left open for future resolution. Another generally held opinion was that new generation, Interconnection, control and communication technologies will continue to change the landscape for small power plants, and that rigid technical rules set early would preclude better options. It was recommended that perhaps the first few DG projects should be monitored for safety and reliability. Perhaps in some cases, redundant safety features may be installed to address fears that the new technologies may not provide adequate protection. Feedback from this monitoring would help improve the mutual confidence and help the implementation of DG going forward.

While most comments were positive and encouraging, there were also a few criticisms of the process. One member felt that there was some posturing on the two sides (utility side, and DG side) at the start of the non-technical process. He felt that the posturing had stopped, and that there was now a strong effort to get the issues on the table and to resolve them. The meeting then adjourned.

2.2.1.2 Outcomes

Outcome of Objective-1: Facilitate consensus on the technical issues of Interconnection.

The most important objective of the workstatement was to form consensus on technical issues of Interconnection (Objective-1). Forming consensus was central to each of the workgroup meetings. How consensus was carried out, though, was modified by the workgroup. The workstatement Task 2.4 was "Test for Consensus and Conduct Voting on PBIRs and Solutions." During the first workgroup meeting the opinion was voiced that voting was divisive, likely to lead to arguments and polarization. One of the first items of consensus was that voting should be dropped, so it was dropped.

The outcome of the revised Objective-1 was that 99 percent of the Revised Rule 21 attained the consensus of the workgroup. The only item where alternate language had to be sent to CPUC along with recommendations was the section on indemnity.[25] The utilities wanted unilateral indemnity, meaning they wanted the DG Applicant to sign a contract that would indemnify the EC against any harm that would come to it arising from the Interconnection. The DG developers argued that the Electricity Producer (EP) could not indemnify the EC against the EC's own mistakes; they argued for mutual indemnity. Although this was a contentious issue, both sides left the door open, conceding they'd rather have no indemnity than the form of indemnity offered by the other. This fallback position is the one recommended by the Commission to the CPUC[26] and subsequently adopted.

The technical section of the Revised Rule 21 (Section 4) contained 100 percent consensus, both in the technical subcommittee and in the full workgroup.

Outcome of Objective-2: Make Interconnection a single uniform process which is internally consistent and predictable statewide.

DG developers and manufacturers were especially intent on creating a single Interconnection process statewide to eliminate inconsistency and uncertainty. Members of the FOCUS team had already done research on the patchwork of utility Interconnection rules, policies and practices.[27] Objective-2 was expressed in an early workgroup meeting as a consensus item. On a number of occasions the workgroup used this objective to check its progress and to keep its work on track.

Before this FOCUS project and OII workshops, each of the three IOUs had its own Rule 21. Each was different from the others. After this FOCUS project, each of the three IOUs are to replace their existing Rule 21 with the one Revised Rule 21. The text of the CPUC decision says:

> Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) are directed to file compliance advice letters to replace their existing Rule 21 with the Model Tariff, Interconnection Application Form and Agreement, within 15 days of the effective date of this order. Within 40 days of the effective date of this order, other respondent utilities (Sierra Pacific Power Company (Sierra), Pacificorp, Mountain Utilities, and Bear Valley Electric) are directed to either file a compliance advice letter adopting the Model Tariff, Interconnection Application Form and Agreement, or a compliance filing in this docket demonstrating compelling reasons why the adopted rules, forms, and agreements should not apply to them.[28]

2.2.2 Serving the Interconnection Process – Objective-3 – Objective-6

2.2.2.1 Objectives

Objective-3 was originally formulated as a general technical support placeholder for the workgroup. The workgroup recognized the need for a short-cut through the Interconnection process for small DG units with Interconnection protection equipment built in. The workgroup agreed that a process of Simplified Interconnection would serve to lower the cost of Interconnection for small DG units.

Objectives 4 and 5 were contained in the workstatement and so were formulated prior to the formation of the OII and without any foreknowledge of the workgroup process through which they would have to navigate. Despite this handicap, these objectives usually became central to the thought and actions of the workgroup. Objective-5, to replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs), was formulated long before the first meeting of the workgroup. The workgroup was profoundly influenced by the idea of IRs being based on performance hurdles rather than prescribing and proscribing technologies or other Interconnection specifics. What this objective gave to the workgroup effort was insulation from obsolescence due to technological change. The framework of safety and reliability of the requirements may then be achieved at ever-decreasing cost by improved technologies. Objective-6, to lower the cost of Interconnection, is facilitated by a number of other Objectives, including Objective-1, Objective 2, Objective-3, Objective-5, Objective-9, Objective-10, Objective-13 and Objective-14. More work is required on some of these objectives in order to maximize cost reduction; that work is contained in the recommendations (Section 4.0 of this paper). +

2.2.2.2 Outcomes

Outcome of Objective-3: Provide a method of Simplified Interconnection.

Objective-3 was to provide a method of simplified Interconnection. Reaching this objective required the creation of two new Interconnection processes, first the Initial Review Process (Appendix A to the Revised Rule 21) and second, the Certification process (Appendix B to the Revised Rule 21). This objective was fulfilled under the workstatement technical support task

(Task 2.5). Both the IRP nor the Certification process came as an unexpected result of the workgroup efforts to fulfill this objective.

Policy Issues

The technical assistance on policy issues (Task 2.5.1) was obviated by the experience of the workgroup. Its purpose was to inform the workgroup of Interconnection policy. Several workgroup members had worked in the Texas and New York Interconnection proceedings and they shared their experiences in detail when questions of precedence in Interconnection policy arose. The workgroup also had utility participants who had many years experience in the old Rule 21, both in project implementation and contracts.

The workstatement also predicted a need for research on the utility distribution systems (Task 2.3.1). This turned out to be infeasible and finally unnecessary. It was infeasible because the workgroup had only two months to make its first recommendations; it was unnecessary because of the participation of the utilities' most experienced distribution system engineers who had most of the knowledge needed to allow the workgroup to make recommendations based on a firm technical basis.

The FOCUS team attended IEEE P1547 meetings[29] in order to implement any standard IEEE might promulgate (workstatement Task 2.5.3). IEEE did not promulgate any standard within the timeframe of the OII. Interconnection discussants concern themselves no less today about implementation of a future IEEE standard. Despite the lack of implementation, the connection with IEEE allowed the Revised Rule 21 to be written in a way to accommodate a future IEEE standard. It was also possible to influence the IEEE by infusion of technical solutions developed by the California Interconnection workgroup.[30]

The Initial Review Process

The IRP[31] was conceived to reduce the burden, on the utility and applicant, of reviewing those DG projects that would have minimal impact on the existing distribution system. The IRP begins after the applicant has submitted a completed application along with an initial application fee to the EC (i.e. utility.)

The IRP can consist of as many as three phases. The first phase is to apply a screening process to determine if the project meets specific criteria. The criteria are based on equipment certification and perceived impact on the Distribution System. If the project passes the criteria, then the project qualifies for a Simplified Interconnection. No other fees, cost, or equipment are required.

If the project does not pass one or more screens of the IRP but the EC determines that only minor changes are necessary to pass the project, then the application continues into Supplemental Review. An additional fee, and additional time, is then required to complete the Supplemental Review. After the required minor changes are made to the project, the EC will allow Interconnection.

During the IRP, the EC may determine that more than minor changes to the project are needed in order to allow Interconnection, and that the project requires a detailed review. If this is the case, the EC will provide to the applicant a cost estimate and study time schedule for the applicant's approval before further effort is expended. This last step gives the applicant the choice of stopping the process or continuing on, knowing the costs and time involved instead of the current open-ended process used now.

Many workshop participants expect the smaller DG projects to qualify for Simplified Interconnection, or require minor changes. Larger DG projects, given their greater impact on the distribution system, will require further study. By showing an applicant the screening criteria up front, the applicant should be able to determine (with some experience and analysis) the possibility of successfully passing the IRP.

In addition to the IRP, Section 4 of the Revised Rule 21 has specific technical requirements to be met, some based on the type of generation technology used. Appendix B also discusses equipment testing and certification requirements that are part of the review process. Testing and certification of equipment, in particular, is an issue that needs further development as standards addressing this issue are just now being formulated and applied (re IEEE, IEC and UL.)

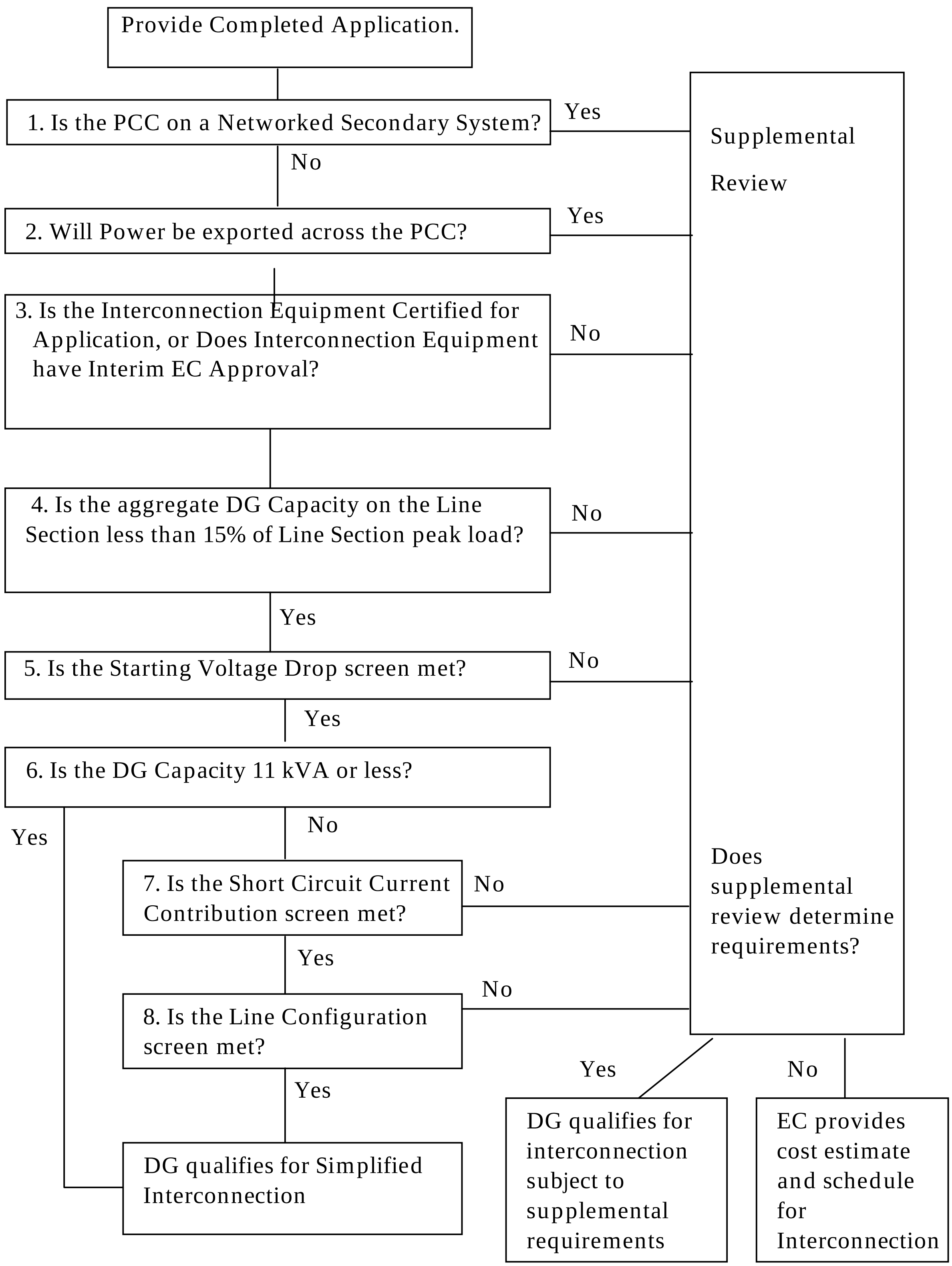

Figure 1. The Initial Review Process

Testing and Certification

Testing and Certification provides a means for verifying that Interconnection equipment meets specified PBIRs. Such testing is often done by each utility on each new piece of equipment. Typically, utilities perform their own testing on relays, transformers, and other pieces of equipment that they deploy. This is a costly and time consuming process that each manufacturer must go through with each utility. There's very little reciprocity among utilities, though the smaller municipal utilities and co-ops will usually accept the results of the larger municipal utilities and IOU's.

The Distributed Generation OII was undertaken to develop a set of PBIRs and procedures that was consistent from one utility to the next that gave reasonable assurance that the DG would not adversely affect the distribution system. Similarly, the testing and certification activity intended to provide a set of test requirements and procedures that utilities and manufacturers would agree are necessary and sufficient to show that the Interconnection requirements had been met.

The proposed California Testing and Certification requirements[32] were developed using as many existing procedures as possible--primarily those specified in Underwriters Laboratories UL-1741. Several procedures were added to supplement those provided in 1741.

Continuing work is necessary to ascertain the necessity and sufficiency of the prescribed tests some of which have not been performed. By monitoring and evaluating installed systems, changes to the test procedures may become apparent.

Certification

Equipment tested and approved (e.g. listed) by an accredited, nationally recognized testing laboratory (NRTL) as having met both the Type Testing and Production Testing requirements is considered Certified Equipment for purposes of Interconnection. Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. Type Testing may be done in the factory / test lab or in the field. At the discretion of the testing laboratory, field-certification may apply only to the particular installation tested. In such cases, some or all of the tests may need to be repeated at other installations.

Testing

For non-certified equipment, that is equipment that has not yet been tested and certified by a NRTL, the workgroup created a process called interim certification which was to define and standardize the tests that any EC could run to determine if a pre-packaged system or an assembly of components address the PBIRs. Some or all of the tests described in Appendix B of the Revised Rule 21 may be required by the EC. The manufacturer or other lab acceptable to the EC may perform these tests. Test results must be submitted to the EC with the Interconnection Application for review and approval under the supplemental review. Approval by one EC for use in a particular application does not guarantee approval for use in other applications or by other ECs.

The NRTL shall provide to the manufacturer, at a minimum, a Certificate with the following information for each device certified:

Administrative:

- Effective date of certification or applicable serial number (range or first in series), other proof that certification is current;
- Equipment model number (s);
- Software version, if applicable;
- Test procedures specified (including date or revision number);
- Laboratory accreditation (by whom and to what standard);

Technical (As appropriate):

- Device rating (kW, kVA, Volts, Amps, etc.);
- Maximum available fault current, Amps;
- In-rush current, Amps;
- Trip points, if factory set (trip value and timing);
- Trip point and timing ranges for adjustable settings;
- Nominal power factor or range if adjustable;
- If the device/system is certified for non-export and the method used (reverse power or under power);
- If the device/system is certified non-islanding.

There are four basic testing categories described in Appendix B: Type testing, Production testing, Commissioning testing, and Periodic testing.

A Type Test is a test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance. UL1741 defines Type Tests for inverters,[33] synchronous generators[34] and induction generators.[35] In addition to the type tests for these generator categories, the following Type Tests were included: Anti-Islanding Test, Non-Export Test, In-rush Current Test, Surge Withstand Capability Test and Synchronization Test.

A Production Test is one performed on each device coming off the production line to verify certain aspects of its performance. Appendix B states that at a minimum the Utility Voltage and Frequency Variation Test procedure described in UL1741 should be performed as part of routine production (100 percent) on all equipment used to interconnect DG to the EC.

Commissioning Tests are performed during the commissioning of all or part of a DG system to achieve one or more of the following:

- Verify specific aspects of its performance;
- Calibrate its instrumentation;
- Establish instrument or Protective Function set-points.

A Periodic Test is one performed on part or all of a DG system at pre-determined time or operational intervals to achieve one or more or the following:

- Verify specific aspects of its performance;
- Calibrate instrumentation;
- Verify and re-establish instrument or Protective Function set-points.

Outcome of Objective-4: Explore the role of advanced communications and metering for Interconnection scheduling and dispatch.

Objective-4 had been envisioned as an exploration of what happens when the distribution grid, currently a one-way delivery of power, is used as a two-way communication network, allowing power and communications to flow in both directions. Time available to the workgroup was very limited and it had decided, in the interest of doing first things first, that it should not attempt to write the rule around how the distribution grid would operate in the future, but around how it operates today. Objective-4 was scaled back in the interest of time. The workgroup decided not to consider reverse power flow, but constrained its work on metering, monitoring and telemetry to one chapter of the Rule 21 (Attachment A, Section 6). Issues considered did not require research.

Outcome of Objective-5: Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs).[36]

Objective 5, workstatement Task 2.3, came from earlier analysis by CADER and ONSITE SYCOM referenced above.[37]

DG technologies include, but are not limited to, photovoltaics, wind, microturbines (operated on a variety of fuel sources), fuel cells, and internal combustion engines. Of these DG technologies, the more important aspect of the technology is whether it requires electronic power conditioning or if it produces an AC current directly. From the perspective of the Interconnection, it is therefore much more important to know the Interconnection technology than the DG technology.

Although there are some exceptions to this principle, the Revised Rule 21 handles exceptions through the use of technology non-specific PBIRs. For example, some wind farms have caused voltage flicker on the utility system. This has been an issue sometimes in the case of induction machines that could inject irritating voltage flicker, and so impact the local grid. Rather than singling out wind power systems, the Rule addresses voltage flicker by setting a maximum threshold for flicker.

Interconnection Technologies

There are three Interconnection technologies of concern for systems designed to operate in parallel with the Distribution System. These are (1) synchronous machines; (2) induction machines; and, (3) inverter machines. Each of these technologies has unique characteristics that require specific design features to allow them to operate safely in parallel with the distribution system. The size of each of these technologies can also have an impact on Interconnection requirements. Rather than attempt to develop separate requirements for each of the technologies and their respective sizes, the technical working group had the foresight to frame the requirements without reference to technology or system size. The technology-neutral requirements allow the requirements to remain the same while the technology changes.

A few exceptions were identified that required a small, technology-specific section, section 4.3.2 of the Revised Rule 21.[38] These exceptions primarily dealt with the different ways these systems synchronize with the Distribution System. Synchronous machines that have a proportionally large available fault current are required to have an automatic synchronizing function. Synchronous units with a Short Circuit Contribution Ratio ((SCCR), see Glossary) of less than 0.05 can be synchronized either manually or automatically. Induction machines rely on the Distribution System for excitation voltage and therefore do not require special synchronizing equipment. Utility-interactive inverter systems already contain the required synchronizing equipment and therefore do not need separate synchronizing equipment.

Technical and safety issues related to the DG technologies and Interconnection technologies, and their impact on the distribution system.

The technical and safety issues related to DG and Interconnection technologies are addressed individually through the series of PBIRs. The issues can be summarized into four major categories: (1) personnel safety; (2) equipment protection; (3) service reliability; and (4) power quality. Each of the PBIR is designed to partially address one or more of these four broad areas of concern. The primary role of the PBIRs as they relate to these four areas is to help eliminate the negative impact of DG systems on the Distribution System. Well-conceived PBIRs facilitate mutually beneficial operation of the DG and Distribution Systems.

Personnel Safety

This refers to not only the safety of Electrical Corporation personnel, but also the safety of the general public. Distribution System designers and operators are required to maintain the safety of the system to prevent danger to personnel. A combination of design practices, work practices, and the equipment protective functions outlined in Section 4 of the Revised Rule 21 are used to address these critical concerns.

Equipment Protection

The equipment referred to here includes both the Electrical Corporation's equipment on the Distribution System and Customer's equipment. All Generating Facilities must be operated so as to prevent damage to Electrical Corporation's equipment. The obligation does not stop there. Although Customer's are required to protect their own equipment from things like normal electrical system transients, Electrical Corporations are often held liable for damages to Customer equipment for a variety of reasons. When other generators interconnect with the same Distribution System, the Generating Facility must have protective functions to prevent them from exacerbating a problem that could damage Customer's equipment. Many of the PBIRs in section 4.3 of the Revised Rule 21, Prevention of Interference, are designed with this concern in mind.

Service Reliability

Providing reliable electrical service is a mandated requirement from the pubic utilities commission. Electrical Corporations take this mandate very seriously and can suffer extensive retribution for not upholding this mandate. This makes the Electrical Corporation very wary of any equipment on their system, generating or otherwise, that might impact system reliability. The protective functions of a Generating Facility must be designed in such a way as to have no adverse effect on Distribution System reliability. As many DG proponents are quick to point out, DG systems can have a substantial impact on improving the service reliability of a particular customer's site. Several studies have also shown that DG systems can also improve local system reliability. These issues are address throughout Section 4 of the Revised Rule 21 and through the screens in the Initial Review Process.

Power Quality

The quality of delivered electrical power is another of the primary concerns of the Electrical Corporation. Poor power quality results in customer complaints and potential lawsuits. This is the reason Electrical Corporations are extremely concerned about the power quality of other generators on their system. Holding the power quality of a DG to high standards is critical in keeping DG from adding to the system power quality problems. These issues are also addressed in Section 4.3 of the Rule, Prevention of Interference.

Type-testing recommendations

The Type-Testing recommendations are found in Appendix B of the Revised Rule 21. This Appendix specifically differentiates among those tests to be done as Type-Tests, those to be done as Production Tests, those to be done as Commissioning Tests, and to be done as Periodic Tests. The majority of the type-testing recommendations come from an Underwriter's Laboratory test standard UL 1741 *Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*.[39] That document is currently being updated to be able to test all Interconnection technology equipment include static inverters for all DG technologies, and multifunction relay packages used on synchronous and induction machines.

Technology certification procedures

Equipment tested and approved (e.g. listed) by an accredited, Nationally Recognized Testing Laboratory (NRTL) as having met both the Type Testing and Production Testing requirements is considered Certified Equipment for purposes of Interconnection. Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. To become Certified for purposes of Revised Rule 21, a manufacturer must submit its equipment for testing at an accredited NRTL for testing to the specifications. Only those tests that apply to the particular piece of equipment need to be performed. An interim solution has also been adopted that allows manufacturers to have a professional engineer oversee the performance of the tests. This procedure is allowed until established testing standards are widely adopted. All tests and specifications are described in Revised Rule 21.

Changes for enhancing communication, metering, control and dispatch of DG, under increasing DG penetration scenarios.

This section was not addressed in the OII Technical working group sessions but provisions for handling these issues are included as Section 6 of the Revised Rule 21.

Description and Purpose of PBIRs

1. **Meet applicable codes.**

    a. Description: The DG facility and Interconnection installation must meet all applicable national, state, and local construction and safety codes.

    b. Purpose: This requirements underlines the fact that the installation must satisfy all related code issues. Since these installations fall under California's Title 21 code requirements, neither the utility nor the DG developer has the option of developing installation procedures that violate those requirements. This was stated emphatically to identify the fact that the DG developer is responsible to perform the installation in full compliance with these codes.

2. **Prevent re-energizing deenergized lines.**

    a. Description: The Protective Functions shall be equipped with automatic means to prevent the Generating Facility from re-energizing a de-energized Distribution System circuit.

    b. Purpose: The re-energizing of de-energized without the consent of the Electrical Corporation circuits is a primary concern of protection engineers. The Generating Facilities must have this function incorporated into its design.

3. **Prevent Unintended Islanding.**

    a. Description: The Generating Facility (GF) and associated Protective Functions shall not contribute to the formation of an Unintended Island.

    b. Purpose: This performance requirement addresses the concern that Generating Facilities outside of the direct control of the Distribution System operator must be designed to avoid contributing to an Unintended Island. Compliance with this requirement may be accomplished through a variety of means including anti-islanding control functions and designing the facility such that the load is always greater than the maximum generation potential.

4. **Prevent Parallel Operation until stable 60 seconds.**

    a. Description: The Protective Functions shall be equipped with automatic means to prevent Parallel Operation of the Generating Facility with the Distribution System unless the Distribution System service voltage and frequency is of specified settings and maintains Stability for 60 seconds.

    b. Purpose: This requirement sets a timeframe for when a DG can automatically resume parallel operation after a utility disturbance. It is set at 60 seconds to allow time for automatic reclosers to return to their normal operating state.

5. **Certification of equipment.**

    a. Description: Certified Equipment contains certified functions that are accepted by all California Electrical Corporations.

b. Purpose: Utility companies must insure that the protection equipment allowed on their Distribution System will perform the functions as expected. The Electrical Corporation can test equipment internally and charge for these services, or accept tests performed as part of an equipment Certification. Most DG manufacturers expect to sell their products in more than one utility service territory and will opt for a broad Certification that applies to all California IOU service territories. This equipment may be installed on a Distribution System in accordance with an Interconnection control and protection scheme approved by the Electrical Corporation.

6. Protect Distribution System from DG.

a. Description: The technical performance requirements are designed to protect the interconnected Distribution System and not the Generating Facility. The Electricity Producer's protective equipment shall not impact the operation of the Distribution System protective devices in a manner that would affect the Electrical Corporation's capability of providing reliable service to Customers.

b. Purpose: This performance requirement prohibits the DG from interfering with the operation of the Distribution System. It specifically points to the fact that the requirements are designed to protect the Distribution System, not the DG. Just as all Customers must protect their own equipment from normal system problems, the Generating Facility is solely responsible for providing whatever protection is needed to address the potential hazards of operating in parallel with the Distribution System.

7. Circuit breakers listed.

a. Description: Circuit breakers or other interrupting devices at the Point of Common Coupling (PCC) must be Certified or "Listed" (as defined in Article 110, National Electrical Code (NEC)) as suitable for the application. This includes being capable of interrupting maximum available fault current.

b. Purpose: The listing of this device is necessary to show that it is properly rated to perform its functions in the electrical environment of the PCC. The fault current available at the PCC is typically higher than any other location on a Customer’s premises.

8. Single failure shall not compromise the safety and reliability of the Distribution System.

a. Description: The Generating Facility shall be designed so that the failure of any one device shall not potentially compromise the safety and reliability of the Distribution System.

b. Purpose: The concern addressed in this requirement is that no one function in the Generating Facility be relied upon as the only method of preventing a safety hazard on the Distribution System as a result of the Generating Facility.

9. Fault-interrupting device.

a. Description: The DG must include a fault-interrupting device.

b. Purpose: The primary concern of this requirement to provide protection in the event a fault occurs line-to-line or line-to-neutral. The NEC also has this requirement. Often this requirement is met with fuses or circuit breakers.

10. Visible open, lockable means of disconnect.

a. Description: The Electricity Producer will furnish and install a manual disconnect device that has a visual break to isolate the Generating Facility from the Distribution System that is appropriate to the voltage level, and is accessible to the Electrical Corporation personnel, and capable of being locked in the open position. (Exception: Distributed Generators connected to the Distribution System through a Non-Islanding inverter smaller than 1kVA)

b. Purpose: The primary need for this means of disconnect is to allow utility line workers to comply with their rules to have access to a visible open, lockable disconnect for all sources. By providing this disconnect, line workers can work on utility-owned conductors adjacent to the Generating Facility without needing to know what type of generating equipment is beyond the switch. The switch also provides a means of lockout should the terms of the Interconnection contract be violated.

11. High over-voltage trip.

a. Description: The high over-voltage trip setting of the Protective Functions shall be 137 percent of the nominal voltage. Above this voltage, the Protective Functions shall cease to energize the system in six cycles.

b. Purpose: This trip setting is for detecting series voltage problems on the Distribution System and to shut down very rapidly in the event of a high voltage excursion. Some of the reasons for these high over-voltage excursions can include major line-to-line faults that can cause permanent damage to customer's equipment. The fast trip time ensures that the Generating Facility is off-line very quickly to minimize damage to equipment. It is also in the best interest of most generating equipment that they disconnect even more quickly than this requirement to protect their own circuitry.

12. Over-voltage trip.

a. Description: The over-voltage trip setting of the Protective Functions shall be 110 percent of the nominal voltage. Above this voltage, the Protective Functions shall cease to energize the system if this condition persists for 30 cycles if the unit is more than 11 kVA. For units of 11 kVA or less, the Protective Functions shall cease to energize the system if this condition persists for 120 cycles.

b. Purpose: The reason for two separate over-voltage requirements is related to the realities of operating equipment on the distribution system. Brief overvoltages are a relatively common occurrence on the distribution system. This is especially true for the less stiff portions of the distribution system where many of the smaller (11kVA or less) systems are likely to be located. In either case (for systems greater or less than 11 kVA) additional delays are needed to allow for short-term, less severe over-voltages. Larger systems (above 11 kVA) may be able to provide some local voltage support to the system and therefore must react more quickly (30 cycles as opposed to 120 cycles) to an over-voltage condition than very small systems.

13. Under-voltage trip.

a. Description: The under-voltage trip setting of the Protective Functions shall be 88 percent of the nominal voltage. Below this voltage, the Protective Functions shall cease to energize the system if this condition persists for 120 cycles.

b. Purpose: The reason for two separate under-voltage requirements is related to the realities of operating equipment on the Distribution System. Brief under-voltages are a relatively common occurrence on the Distribution System due to starting of motors and other large loads. This is especially true for the less stiff portions of the distribution system where additional delays are needed to allow for short-term under-voltages that commonly occur under normal conditions. This allows the Generating Facility to operate through these normal excursions without nuisance trips.

14. Low under-voltage trip.

a. Description: The low under-voltage trip setting of the Protective Functions shall be 50 percent of the nominal voltage. Below this voltage, the Protective Functions shall cease to energize the system if this condition persists for six cycles.

b. Purpose: This trip setting is for detecting series voltage problems on the Distribution System and to shut down very rapidly in the event of a low voltage excursion. Some of the reasons for these very low over-voltage excursions can include major line-to-ground faults. The fast trip time ensures that the Generating Facility is off-line very quickly to allow the Electrical Corporation’s equipment to detect and address the problem with their Distribution System equipment designed for dealing with these situations.

15. Flicker limits.

a. Description: Any voltage flicker at the PCC caused by the Distributed Generator should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519, *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.*[40]

b. Purpose: This requirement is necessary to minimize the adverse voltage effects produced by a GF to other customers on the Distribution System. Induction generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded.

16. Over-frequency trip.

a. Description: The over-frequency trip setting of the Protective Functions shall be 60.5 Hertz. A Generating Facility (GF) operating at a frequency above 60.5 Hertz shall cease to energize the system in six cycles.

b. Purpose: The over-frequency trip setting is meant to address two concerns. The first concern is that of Unintentional Islanding. A tight upper frequency setting will cause the GF to cease to energize the Distribution System should the local load be smaller than the GF and the load-to-generation imbalance cause even a brief over-frequency condition. The second concern is for the case where the portion of the Distribution System connected to the GF undergoes a large enough load-to-generation imbalance to cause the frequency in region to rise. In this case, all generation outside the direct control of the Electrical Corporation or the system operator must cease to energize the system until stability is restored. The quick response time is meant to protect equipment susceptible to higher frequencies, but the response time is slow enough that short-term disturbances will not cause nuisance tripping.

17. Under-frequency fast trip.

a. Description: The under-frequency fast trip setting of the Protective Functions shall be 59.3 Hertz for fast frequency excursions. A Generating Facility (GF) operating at a frequency below 59.3 Hertz and changing at a rate of 0.2 Hertz per second or faster shall cease to energize the system in six cycles. If the unit is incapable of evaluating the rate of change of frequency, 59.3 Hertz shall be the only low frequency trip setting.

b. Purpose: The fast under-frequency trip setting is meant to address the concern over Unintentional Islanding. A tight under frequency setting will cause the GF to cease to energize the Distribution System should the local load be greater than the GF and the load-to-generation imbalance cause even a brief under-frequency condition. The response time is slow enough that very short-term disturbances will not cause nuisance tripping.

18. Under-frequency slow trip.

a. Description: The under-frequency slow trip setting of the Protective Functions shall be 58.0 Hertz for slow frequency excursions. A Generating Facility (GF) operating at a frequency below 58.0 Hertz and changing at a rate less than 0.2 Hertz per second shall cease to energize the system in six cycles.

b. Purpose: The slow under-frequency trip setting is meant to address the case where the portion of the Distribution System connected to the GF undergoes a large enough load-to-generation imbalance to cause the frequency in region to fall below 58 Hertz. In this case, all generation outside the direct control of the Electrical Corporation or the system operator must cease to energize the system until stability is restored. Up to the time that the 58.0 Hertz limit is reached, the

GF may actually assist the Distribution System operator in restoring normal operating conditions.

19. Harmonics compliance with IEEE 519.[41]

a. Description: Harmonic distortion shall be in compliance with IEEE 519.

b. Purpose: IEEE 519 is the document that sets the limits for harmonic distortion on Electric Power Systems. Rather than developing a new set of requirements independent of this standard, it was decided that this standard be adopted. It is also undergoing a revision currently so that referencing the standard in general without reference to a specific revision or section will allow the California standard to stay current with the latest version as it becomes available.

20. Harmonics exception to IEEE 519—treat DG like site loads.

a. Description: The harmonic distortion of a Distributed Generator at a Customer's site shall be evaluated using the same criteria as the loads at that site.

b. Purpose: This exception is meant to address an important concern with the existing version of IEEE 519-1992. This version forces a Customer's site that installs a GF to come into compliance with the most stringent harmonic requirements regardless of the characteristics of the local Distribution System. This is overly conservative and does not have sufficient technical basis to cause the California technical working group to adopt IEEE 519 without comment. This particular concern is currently being debated in the IEEE 519 revision process and will likely find its way into the next version of 519. At that time, this exception will no longer be relevant.

21. Limit Direct Current (DC) injection.

a. Description: The Distributed Generator (DG) should not inject direct current greater than 0.5 percent of rated output current into the Distribution System under either normal or abnormal operating conditions.

b. Purpose: This particular performance requirement is designed to address one of the primary reasons utilities require isolation transformers on DG, to control DC injection. If DC injection can be controlled via active circuitry that senses and removes the DG in the event of a problem, there is not need for a transformer to decouple the power source from the Distribution System. The 0.5 percent of rated output current limit was established in IEEE 929-2000, *Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*,[42] as a limit below which standard Distribution System transformers will not saturate nor cause service reliability problems.

22. Maintain power factor limits.

a. Description: The Distributed Generator shall be capable of operating at some point within a range of a power factor of 0.9 (either leading or lagging). Operation outside this range is acceptable provided the reactive power of the Distributed Generator is used to meet the reactive power needs of on-site loads.

The Electricity Producer shall notify the Electrical Corporation if is using the Distributed Generator for power factor correction.

b. Purpose: The purpose of power factor limits are to guard against a GF that would attempt use the Distribution System for reactive power services well above those allowed to loads. It is even possible for a device to be constructed that takes reactive power from the Distribution System and then converts it into useful power to displace site load or sell to the Electrical Corporation. If allowed, this would cause all other customers to pay for the cost of this mode of operation.

23. 20 kVA limit to single-phase units on shared secondaries.

a. Description: For single-phase Generating Facilities connected to a shared single-phase secondary, the maximum capacity shall be 20 kVA.

b. Purpose: To allow for all customers on a shared single-phase secondary to have equal access to the installed distribution facilities, a limit is placed on individual Customer’s sites. This limit allows for some diversity of loads and generation at each of the services in a shared secondary without overloading the serving distribution transformer.

24. 6 kVA limit for imbalance of single-phase, center-tap 240-Volt services.

a. Description: Generating Facilities applied on a center-tap neutral 240-Volt service must be installed such that no more than 6 kVA of imbalance in capacity exists between the two sides of the 240-Volt service.

b. Purpose: The 6 kVA limit for imbalances on single-phase 240-Volt services is to protect from excessive imbalances causing overloading of the Electrical Corporation’s serving neutral conductor. This neutral conductor is often undersized since standard services almost always have less current flow on the neutral conductors than on either of the 240-Volt supply conductors. The unique situation that an imbalanced Generating Facility presents can cause the neutral current to be significantly higher than it would be without the imbalanced generator.

25. DG capacity supplied by single-phase Dedicated Transformer (DT) limited by the DT nameplate rating.

a. Description: For dedicated distribution transformer services, the limit of a single-phase Distributed Generator shall be the transformer nameplate rating.

b. Purpose: Particularly in rural areas where no three-phase service exists, a large single-phase distribution transformer of up to 100 kVA in size may serve some customers. This provision allows for these customers to install larger single-phase generators since the distribution system serving the customer has the capacity and no other customers are served by the transformer (no shared secondary).

26. Synchronizing required by synchronous generators with a SCCR greater than 0.05.

a. Description: Automatic synchronizing is required for all synchronous generators which have a SCCR of greater than 0.05.

b. Purpose: This is a performance requirement that does not allow manual synchronizing for GF that are large in comparison to the Line Section on the Distribution System to which they are connected. The reason this is not allowed in these cases is that synchronizing improperly can cause severe voltage excursions that can be a nuisance to some customers and possibly cause damage to other customer's equipment.

27. Induction generators shall not require separate synchronizing.

a. Description: Induction Generators do not require separate synchronizing equipment.

b. Purpose: Induction generators inherently synchronize with the grid based on their speed. This means that it is unnecessary to install separate synchronizing equipment. Other issues are of importance. As induction machines start to generate, they can cause voltage fluctuations that can become severe enough to require the installation of corrective capacitors or other means. These corrective capacitors have been known to cause ferroresonant voltages that can cause damage to sensitive equipment.

28. Inverters shall not require separate synchronizing.

a. Description: Utility-interactive inverters do not require separate synchronizing equipment.

b. Purpose: In order for an inverter to be classified as utility-interactive, it must have its own, on-board synchronizing software. This software not only allows it to synchronize but also must protect the unit from mis-synchronizing. If the unit does not have this specialized software, the unit will be destroyed by the utility system. This is why the Revised Rule 21 specifically prohibits non-utility-interactive inverters operating in parallel with the Distribution System.

29. Does DG qualify for net metering?

a. Description: Does the DG unit fulfill the performance and technology requirements of the California net metering legislation?

b. Purpose: The net metering law has a separate process for developing the Interconnection Requirements. Since this is a specialized segment of the DG market, it is identified early in the IRP screening process[43] so that time is not wasted developing a set of requirements that is not in compliance with that of net-metered systems.

30. Is DG installed on a network secondary?

a. Description: Is the Generating Facility installed on a networked secondary system?

b. Purpose: This screen identifies that special considerations must be given to DG on networked secondary distribution systems because of the design and operational aspects of network protectors. Since radial systems do not contain network protectors, there are no such considerations for radial distribution systems.

31. Will power be exported?

a. Description: Will power be exported across the Point of Common Coupling (PCC)?

b. Purpose: Systems that do not have power exported across the PCC will not require immediate adjustments to the local Distribution System. This eliminates several evaluation steps from the review process.

32. Reverse-power function.

a. Description: One option to insure power is never exported across the PCC is by implementing a reverse-power Protective Function at the PCC.

b. Purpose: This is a common way for site generation to operate when the facility load is always greater than the generation. This is often accomplished through a reverse-power relay designed to open any time the site begins to be a net generator above some predetermined threshold. This performance requirement does not require that the function be a relay or any specific device. The unit must, however, perform the very same functions as a reverse-power relay.

33. Under-power function.

a. Description: One option to insure power is never exported across the PCC is by implementing an under-power Protective Function at the PCC.

b. Purpose: This is similar to a reverse-power function and is another common way for site generation to operate when the facility load is always greater than the generation. This is often accomplished through an under-power relay designed to open any time the site load drops below a certain threshold. This performance requirement does not require that the function be a relay or any specific device. The unit must, however, perform the very same functions as an under-power relay.

34. Limit incidental export—1st PBIR solution—no more than 25 percent of service entrance equipment.

a. Description: The aggregate DG capacity of the Generating Facility must be no more than 25 percent of the nominal ampere rating of the Customer’s Service Equipment.

b. Purpose: The limit incidental export option has three separate PBIRs. The first requires that the nominal ampere rating of the Generating Facility must be no more than 25 percent of the Service Entrance Equipment. This means that if a facility has a 400-amp service, the maximum ampere rating of the GF is 100-amps. This is meant to provide a sufficient site load to assure little or no export is possible.

35. Limit incidental export—2nd PBIR solution—no more than 50 percent of transformer rating.

a. Description: The total aggregate DG capacity must be no more than 50 percent of the transformer rating (This capacity requirement does not apply to customers taking primary service without an intervening transformer)

b. Purpose: The second PBIR or the three limited incidental export screens requires that the GF have a capacity no greater than 50 percent of the serving transformer rating. This is another means to provide sufficient site load to assure little or no export is possible. As an example, a 100 kVA GF would need to be at a site with a transformer of at least 200 kVA.

36. Limit incidental export—3rd PBIR solution—Certified as non-islanding.

a. Description: The DG must be certified as non-islanding.

b. Purpose: The third PBIR of the limit incident export screen is that it must be certified as non-islanding. This requirement is to ensure that a reverse-power function is unnecessary for the purpose of anti-islanding.

37. DG is limited to 50 percent of minimum Customer's verifiable minimum annual load.

a. Description: The DG capacity must be no greater than 50 percent of the customer's verifiable minimum annual load.

b. Purpose: This option for proving that a site will never be a net generator states that DG capacity is only 50 percent or less of the customer's minimum annual load. This is fairly difficult to verify since the minimum load of a facility is rarely measured. This provision is primarily designed for sites that are so clearly larger than the DG, that the minimum site load is substantially greater than the maximum output of the DG.

38. Does the DG have interim approval from the EC?

a. Description: Does the DG unit have an interim approval from the Electrical Corporation?

b. Purpose: This is a temporary approval that a Electrical Corporation may grant an Applicant while it is pursuing certification. It is meant to facilitate the installation of new DG so that developers can begin to install a product while they are obtaining full Certifications. It is not a substitute for the Certification process.

39. Is the DG Certified?

a. Description: Is the DG Certified for the intended use.

b. Purpose: This performance requirement is the cornerstone of many of the PBIRs. Without some process to certify that a DG can meet a particular PBIR, the value of a functional requirement is severely limited.

40. Is the aggregate DG Capacity on the Line Section less than 15 percent of Line Section Peak Load?

a. Description: The aggregate DG capacity on the line section is less than 15 percent of Line Section Peak Load.

b. Purpose: This is a requirement designed to make sure that the aggregate DG capacity on a line section is well below the maximum peak load on that section. The purpose is to provide a check for the protection engineer to determine whether a significant amount of DG has already been installed on a line section. If this is the case, it may require a more serious analysis to see if a line upgrade is necessary.

41. Is the DG capacity 11 kVA or less?

a. Description: The DG is 11 kVA or less.

b. Purpose: The purpose of this limit is put a lower limit on the need to review the short circuit current contribution and the line-configuration screens of the IRP. At this level, the last two screens of the IRP will always be met so there is no need to go to through the process to verify this fact.

42. Calculate Short Circuit Contribution Ratio.

a. Description: Short Circuit Current Ratio (SCCR) is the ratio of the short circuit current contribution of the GF divided by the short circuit current contribution of the utility at the PCC.

b. Purpose: This ratio is designed to determine the relative size of the GF in comparison to the local Distribution System. It is a very important metric in determining the impact of the GF on the local Distribution System protection requirements.

43. Is the short circuit current contribution screen met?

a. Description: At primary side (high side) of dedicated distribution transformer, for the specified feeder, the sum of the Short Circuit Contribution Ratios (SCCR) of all DG's on the feeder must be less than or equal to 0.1. At secondary (low side) of a shared distribution transformer, the short circuit contribution of the proposed DG must be less than or equal to 2.5 percent of the interrupting rating of the Customer's Service Equipment.

b. Purpose: Both of the short circuit current contribution requirements are meant to show that the GF has a small enough impact that it is unnecessary to perform a short circuit contribution analysis. These analyses can be quite involved and add a significant amount of unpredictability in the cost of an engineering analysis.

44. Is the Line Configuration screen met?

a. Description: If the DG is a three-phase generator connected to a four-wire service, the aggregate DG capacity must be limited to 10 percent of the line section capacity.

b. Purpose: This performance requirement limits overvoltages to the Electrical Corporation's, or Customer, equipment caused by loss of system neutral grounding during an Unintentional Island before the operating time of anti-islanding protection.

45. If it passes all screens, DG qualifies for Simplified Interconnection.

a. Description: The combination of passing the Initial Review screens classifies the unit as a Simplified Interconnection and determines the Interconnection Requirements.

b. Purpose: The purpose of the screening process is to help identify the simple cases for Interconnection. The series of screens provides substantiation for why a Simplified Interconnection is warranted. It addresses the extent of issues that must be reviewed to establish a DG installation for Simplified Interconnection.

46. Unintended Islanding for DG that fails export screen—non-islanding system.

a. Description: Generating Facilities must mitigate their potential contribution to an Unintended Island. This can be accomplished by incorporating certified non-islanding control functions into the Protective Functions.

b. Purpose: The reason for this option is to provide for DG that does not pass the screen to comply with the requirement to not support an Unintended Island.

47. Unintended Islanding for DG that fails export screen—local loads much greater than DG capacity.

a. Description: Generating Facilities must mitigate their potential contribution to an Unintended Island. This can be accomplished by verifying that local loads sufficiently exceed the load carrying capability of the Generating Facility.

b. Purpose: The reason for this option is to provide for DG that does not pass the screen to comply with the requirement to not support an Unintended Island.

48. Unintended Islanding for DG that fails export screen—transfer trip function.

a. Description: Generating Facilities must mitigate their potential contribution to an Unintended Island. This can be accomplished by transfer trip or equivalent function.

b. Purpose: The reason for this option is to provide for DG that does not pass the screen to comply with the requirement to not support an Unintended Island.

49. DG with SCCR greater than 0.1 must have fault detection function.

a. Description: A Generating Facility with an SCCR exceeding 0.1 or that do not meet any one of the options for detecting Unintended Islands, shall be equipped with Protective Functions designed to detect Distribution System faults, both line-to-line and line-to-ground, and promptly remove the Generating Facility from the Distribution System in the event of a fault.

b. Purpose: This requirement is designed to provide the fault protection requirements necessary for GF that are a major source of fault current on the local Distribution System.

50. DG with SCCR greater than 0.1 that cannot detect faults within two seconds must have transfer trip function.

a. Description: Generating Facilities that cannot detect faults within two seconds may require transfer trip function or equivalent.

b. Purpose: This requirement is designed to address large GF that cannot detect faults within two seconds and that are a major source of fault current. This classification needs a transfer-trip function to disconnection the GF in the case of a fault.

Outcome of Objective-6: Lower the cost of Interconnection.

The project succeeded in lowering the cost of Interconnection, according to current estimates of Interconnection costs. Cost reductions are found mostly in the Interconnection study, which is now defined, both in total cost and in duration (see Objective-14). An additional phase to this work could verify empirical cost savings in actual projects.

The stated purpose of the OII was to discover and recommend how to remove barriers to Interconnection. Page A-1 of the FOCUS workstatement says "[the] Contractor's objective for its participation in the Commission's OII is to produce recommendations on Interconnection which if implemented will lead to Interconnection cost reduction." Analysis by CADER and numerous comments made at the June 1, 1999 Hearing at the CPUC[44] expressed the opinion that high cost was a barrier to Interconnection. Project cost includes both the carrying cost (project financing cost per unit of time to installation), equipment cost and labor cost.

Every project developer knows there is one cost more deadly than these: when prior to signing up, a customer loses interest because of uncertainty about the cost and uncertainty about the amount of time necessary to complete a project. It has been observed before that markets can tolerate risk but cannot tolerate uncertainty. The Revised Rule 21 reduces uncertainty of Interconnection during the critical Application process.

Rule 21 Section 3.1.2 and 3.1.3 set Interconnection study time limits that reduce cost and increase Applicant certainty. Section 3.1.2 sets a 10-day limit for the EC to acknowledge receipt of the Application and to check the Application for completeness. If the Application is incomplete, the 10 days is reset and restarted on receipt of the revised Application. Section 3.1.3 gives the EC an additional 10 days to complete the IRP. At the end of the IRP, the EC informs the Applicant whether it qualifies for Simplified Interconnection; if not, the EC specifies the cost and time necessary for supplemental review. Section 3.1.3.3 states: "The supplemental review shall be completed, absent any extraordinary circumstances, within 20 business days of receipt of a completed Application."[45]

If supplemental review is not adequate, the EC and Applicant must negotiate a detailed study. The overall cost of this process is limited to $1400 and, for a rejected Application, is only $400.

If a DG installation is especially large or if multiple sites are involved, the EC and Applicant are provided with Revised Rule 21 with a procedure for negotiating fees and time schedules for the Interconnection study.

All the foregoing add certainty to the process and help reduce the carrying cost and the study fee cost of Interconnection. The FOCUS workstatement predicts that DG units passing the IRP will be spared additional hardware costs that could increase total installed cost per kW by $100 to $330 (10 percent to 33 percent at $1000/kW).

2.2.3 Serving the Interconnection Process – OII Objective 7 – Objective 12

2.2.3.1 Objectives

This group of objectives came from the OII and served to guide the workgroup effort. The workgroup completed them to the extent they lay within the scope of the Revised Rule 21.

The OII envisioned the Revised Rule 21 as a temporary measure until IEEE national standards became available. However, the workgroup soon discovered that its work was fulfilling needs that would never be addressed by IEEE. Actual training for government agencies, Objective-10, received limited attention in the FOCUS-I effort. Although some objectives, particularly Objective-10, could profit from greater attention, all of the OII Objectives were taken up successfully by the workgroup.

2.2.3.2 Outcomes

Outcome of Objective-7: Fulfill the need for interim standards.

In the OII, the Revised Rule 21 is referred to as a set of 'interim standards', in expectation of their supercession by IEEE standards. The outcome of the Revised Rule 21, however, is neither interim nor is it a standard. It is not interim because the IEEE will not produce anything that will replace it; also each IOU has been directed by the CPUC to implement this tariff. It is not a standard because neither the Commission nor the CPUC has standards-making authority. The outcome of this objective was to fulfill the need for uniform Interconnection requirements and procedures. In this case 'requirements' refers to technical PBIRs, Rule 21 section 4 and Appendix A & B; 'procedures' refers to rules contained in Rule 21 sections 1 – 3 and 5 – 7.

Outcome of Objective-8: Address safety issues.

The full statement of the purpose of the FOCUS project is to reduce cost without any sacrifice to the safety and security of the distribution grid. All the PBIRs are written to encapsulate a single safety issue. (See Section 2.2.5 Outcome of Objective-5.) The purpose of Rule 21 is to maintain safety during Interconnection.

Outcome of Objective-9: Define the scope and feasibility of Type Testing.

The scope was broadened by the Testing and Certification subgroup to include Production Testing, Commissioning Testing and Periodic Testing as well as Type Testing. Certified equipment is equipment which has passed a Certification Test, defined as "a test adopted by an Electrical Corporation that verifies conformance of certain equipment with CPUC-approved performance standards in order to be classified as Certified Equipment. Certification Tests are performed by NRTLs."[46] At this time, there are no CPUC-approved performance standards, so no Interconnection equipment in California is presently certified. Until the CPUC standard is created and adopted, the workgroup began work on a process of interim certification, which would be done by each utility on each DG manufacturer's equipment. That process is not yet clearly defined. (See Section 2.2.3.3 for a description of Testing and Certification; See Attachment A, Appendix B for more details.)

Outcome of Objective-10: Accelerate the adoption of DG by training and informing government agencies.

The Revised Rule 21 has been provided to all government agencies who were stakeholders in the workgroup (CPUC, Office of Ratepayer Advocates (ORA), the California Air Resources Board (CARB)) and it is now available to visitors to the Commission's website.[47] Members of the CPUC, ORA, CARB, municipal utilities and individual air districts have participated in Hearings and workgroup meetings. The FOCUS team members have made presentations at four Hearings on the matters of Interconnection and Permit Streamlining. FOCUS team members and individual members of the workgroup have made presentations on Interconnection and permit streamlining at multiple conferences, including the Distributed Power Coalition of America and California Alliance for Distributed Energy Resources (DPCA/CADER) DG conference and at IEEE conferences.

Outcome of Objective-11: Define the scope of technologies covered by Rule 21.

Both the technical and non-technical subgroups agreed that the discussions should not be limited by technology type or by generator size (in kW). Instead, the scope was limited electrically and jurisdictionally by stating that the rule applies only to generation on the distribution system level.

Revised Rule 21 covers three Interconnection technologies: synchronous machines, induction machines and inverter machines. (See Section 2.2.5.1 for more detail).

Outcome of Objective-12: Make changes to utility tariffs proceeding from Interconnection rules.

Revised Rule 21 represents a complete rewriting of the utility tariff on Interconnection. Each of the sections of the existing Rule 21 were gutted. Several structural changes were made to major sections of the Rule.

Standby tariffs and Customer rate tariffs also affect the viability of DG projects but they do not proceed from Interconnection rules. Therefore they fell outside of this objective. Also, the Commission's responsibility under the OII was to Interconnection alone, the workgroup deferred discussion of these issues. All tariffs which affect DG but do not proceed from Interconnection rules were taken up by the CPUC Energy Subcommittee.

2.2.4 Serving the Interconnection Process – Workgroup Objective-13 and Objective-14

2.2.4.1 Objectives

The last two objectives came from the workgroup itself and served to fulfill needs that hadn't been addressed by the other objectives. The workgroup felt its task was tied up with the fate of small DG, units under 1MW, which today bear Interconnection costs which often make sound projects economically infeasible. Whereas Interconnection costs for large units, greater the 100MW, for example, might only be 1 percent of the project cost, Interconnection can be as much as 33 percent of the total installation cost of a small unit. The second item the workgroup took on was utility discretion of study fees. Many DG developers had experienced the chilling effect utility discretion of Interconnection study fees could have on a project and they were eager to make sure that would not be the case after Rule 21 was revised.

2.2.4.2 Outcomes

Outcome of Objective-13: Facilitate Interconnection of small units.

The IRP is designed specifically for smaller certified units to be interconnected with a minimum of time and expense. The IRP does not differentiate units according to kW sizing to avoid putting arbitrary limitations into the rule. (See section 2.2.4.2 for a discussion of IRP. See Attachment A, Appendix A for the actual IRP included in the Revised Rule 21).

The cost impact of Interconnection is greater as a percentage of total cost for smaller units. The workgroup's effort has been directed at reducing cost for the smaller units so that Interconnection is not a barrier to DG smaller than 1MW. (See section 4.3 and the Recommendations section for Objective-13 for an analysis of the affect of the FOCUS contract on the Interconnection cost of smaller units.)

Outcome of Objective-14: Eliminate utility discretion of study fees.

The committee addressed this issue fully. Discretion of study fees has been eliminated from every aspect of the Initial Review Process. The requirement of Supplemental Review is that the cost and time to complete it must be stated. That gives the Applicant an opportunity to decide whether to continue the project at the state cost or not. The cost and time for delivering an IRP has been capped now at 20 days. The cost is now $800 for Simplified Interconnection, $1400 for Supplemental Review or to receive the cost and time for a detailed study. Study fees are set at $400 pre-contract initial review, $600 supplemental review, $400 post-contract review. Detailed reviews must be done on a case-by-case basis due to their complexity and non-uniformity. No standardization of those costs is possible.

2.3 Interconnection Conclusions and Recommendations

2.3.1 Conclusions

2.3.1.1 The Integrated Review Process

All stakeholders desired a better way of reviewing and processing applications for DG projects. All agreed that a basic set of uniform IRs were desirable and attainable. In many ways, attaining consensus on the technical issues was easier than attaining consensus on non-technical issues, such as contract language, cost allocation, indemnity, and liability insurance. The June[48] and October[49] Commission DG reports discuss specific areas of disagreement between stakeholders.

The PBIRs and IRP are a new approach and should allow innovative solutions to current and future Interconnection requirements. Having a universal method of reviewing project applications, and common screening criteria, will result in:

- A better understanding by applicants of what the process is and what criteria they will be judged by;
- A framework for reviewing applications that all utilities can impartially adopt;
- Reductions in costs by both applicants and utilities as a result of the more streamlined and uniform IRP;
- Promoting fairness by applying the same review process to all applications;
- Greater Applicant certainty

2.3.1.2 Technical Interconnection Requirements – California and IEEE

Section 4 and Appendix B of the Revised Rule 21 provide an initial basis for determining technical IRs and equipment testing and certification requirements, for eventual integration with national standards as they are adopted. Many of these technical IRs could be considered interim in nature. Whether or not the California IRs should be replaced, or modified, by national standards is an issue that should be investigated by the "Forum for Addressing Future Changes to the Rule".[50] It is premature to state that any national standards should replace the work of this workgroup until the results of the national standards effort are known. This may take months or even years.

Testing and certification standards for Interconnection equipment, in particular, are still being developed by the IEEE, UL, IEC and other standards groups. This is an area where national standards will probably have the greatest impact on the California IRs.

What these standards groups will not address is the implementation process - how DG projects are reviewed, review criteria, contract language, jurisdiction issues, etc. The CPUC and other agencies having authority will determine the implementation process. The Revised Rule 21 will incorporate both the implementation process and technical requirements, and for this reason will not totally be replaced by national standards.

2.3.2 Recommendations

2.3.2.1 Specific Recommendations

Although all objectives produced results, some objectives do not contain recommendations because no additional change is useful or necessary. Objectives with specific recommendations follow.

Objective 1: Facilitate consensus on the technical issues surrounding Interconnection rules.

- The CPUC has adopted the consensus of the workgroup
- The Commission's recommendation on this issue is for the CPUC to eliminate indemnity from the Revised Rule 21, that is, to provide no indemnity.

Objective 2: Make Interconnection a single uniform process which is internally consistent and predictable statewide.

- Additional work is needed to make sure that each EC's implementation of the Revised Rule 21 is consistent with the Rule.
- Additional work is needed to make sure that the Rule works in practice.
- Additional work is needed to create a consistent implementation of Certification.

Objective 4: Explore the role of advanced communications and metering for Interconnection scheduling and dispatch.

- A future research project should be funded to address advanced communications that would allow operation of the Distribution System as a smart digital network.

Objective 6: Lower the cost of Interconnection.

- Additional research is needed to ascertain actual installed cost savings.
- Additional monitoring of actual DG installations is necessary to give utilities greater confidence in newer, less expensive Interconnection devices and systems.
- Actual testing and certification of protection packages for DG units is necessary to allow for Simplified Interconnection.

Objective 8: Address safety issues.

- The grid response to DG systems should be measured in a number of different actual installations to determine whether the safety standards of Revised Rule 21 are adequate and to determine how they may be most cost effectively upheld.
- The IEEE P1547, once it becomes a standard, should be adhered to for all safety issues.

Objective 9: Define the scope and feasibility of type testing.

- The Testing and Certification work completed under this contract goes beyond the work done in any other state to date. However, it needs to be fully integrated with the current IEEE work.
- At high levels of DG penetration, other requirements and corresponding test procedures may need to be defined.
- Further work is needed on NRTL certification, testing procedures and interim certification.

Objective 10: Accelerate the adoption of DG by training and informing government agencies.

- Goverment regulators who are in a position to accelerate DG should have DG training and informational materials available to them.
- A program should be developed and funded which can provide DG training statewide.

Objective 11: Define the scope of technologies covered by Rule 21.

- The CPUC has adopted this approach.

Objective 12: Make changes to utility tariffs proceeding from Rule 21.

- The CPUC will have to decide certain key tariff issues, such as standby charges, in another part of the Order Instituting Rulemaking (OIR).

Objective 13: Facilitate Interconnection of small units.

- Further research is needed on the proportional cost and timeliness of Interconnection of small units.

Objective 14: Eliminate utility discretion of study fees.

- Further study is needed to assess the efficacy of the Interconnection Application process.

2.3.2.2 General Recommendations

Now that the CPUC has adopted Revised Rule 21, a method of overseeing future modifications should be established. One recommendation at the end of Publication 700-00-014 was to establish a “forum for future work” to make future modifications to Revised Rule 21. Its mission should include overseeing the implementation of the Rule by the utilities, further work on Testing and Certification, integrating national standards as they become available, and recommending modifications to the Rule based on experiences of the ECs and Applicants.

A concerted effort should be made to encourage municipal utilities, irrigation districts, and cooperatives to adopt Revised Rule 21, or the closest facsimile to it they can integrate. A uniform set of PBIRs, statewide, would greatly enhance the development of DG in California.

Regulators who will be tasked with siting and permitting DG projects need training on DG impacts and best practices. Front-line personnel who will be handling the actual Interconnection of DG need training on the IRP, Certification, best practices and coming IEEE standards. Funding should be made for these training programs.

2.3.3 Benefits to California

2.3.3.1 Relieving the Capacity Constraint

We stated at the outset that California is experiencing capacity constraint of crisis proportions. The electrical reserves in the state have been less than 1.5 percent for more than four weeks this winter (Stage Three emergency). The Commission’s OII Interconnection recommendation, Revised Rule 21, is timely; CPUC adoption of Revised Rule 21 is timely. The electricity price and supply problems of this past year has caused many companies to consider their options for reliable electrical supply. Some DG industry participants believe the market for on-site generation is poised to take off. The new market will rely on improvements to the Interconnection process promised by Revised Rule 21. Manufacturers need clear and consistent requirements and certification tests to guide the manufacture of their DG technologies. Utilities need clear and consistent methods for reviewing DG projects. Establishing California requirements early in the developing national DG market will solidify California as a prime market for DG.

The work completed here could accelerate DG benefits, including greater market penetration, for customers, ECs, utilities, and manufacturers, which may include lower DG power prices and better reliability. In addition, a standard Interconnection process can provide more cost-beneficial MWs to help minimize potential blackouts and its secondary impacts (indirect and induced) on the general economy.

The work of the Commission Workgroup will have effect on the national standards being formulated by the IEEE and UL. This effect is not only felt through common membership in these groups but also in the approach taken. The concept of a PBIR has already influenced the way technical requirements are being written by the IEEE P1547 Workgroup. California will benefit by having national standards that are similar to those in California.

2.3.3.2 The High Cost of Interconnection

No Interconnection has yet been concluded using this new process so estimations of cost reductions are speculative. The following examples, however, suffice to illustrate the cost differences that are likely to be encountered before and after the FOCUS work on Rule 21.

Existing utility protection requirements generally require the project developer to add secondary protection hardware to that already incorporated as part of the DG control equipment. For inverter-based DG, such as microturbines and fuel cells, control and protection functions are usually implemented in software. Adding more hardware means higher installation costs.

One method Electricity Producers have used to meet this requirement is to apply a multi-function solid-state relay as back-up protection. The relay hardware alone costs $3000 to $5000 per installation, depending on which protection functions and auxiliary equipment (current transformers, et cetera) are used. The cost of installing this relay at a site can add another $3000 to $5000, depending on the difficulty of incorporating the relay wiring scheme into the existing power circuits and any on-site testing required. For a 30 kW DG, this would increase the installation costs in the range of $200 to over $300 per kW. For installed costs without this relay (in the range of $1000 to $2000 per kW), the increase in cost using this relay can range from 15 percent to over 30 percent. These figures are only approximate, but do indicate the impact of adding one or more additional pieces of hardware.

Costs of solutions to other types of protection problems can be even greater. One of the concerns addressed in the IRP deals with potential overvoltages, caused by the DG, on the distribution line in the event of a line outage. A solution to this problem in one case, proposed by the host utility, was to add a ground bank transformer on the utility side of the service transformer. The cost of this solution to the developer would have been $30,000. In this case, the project size was halved in order to eliminate this requirement.

2.3.3.3 Reducing the Cost of Interconnection

If DG projects can be designed to meet the technical requirements (and the IRP) of the new Revised Rule 21, these potential problems would not be an issue. Additional equipment would not be needed. Projects would not be delayed. Additional time, and costs, for meetings, analysis and hardware would not be required. Both the utility and developer could reduce both labor and equipment costs.

3.0 CEQA Review and Permit Streamlining Project

Distributed Generation facilities[51] may be required to receive permits from local governing bodies (e.g., city council, county board of supervisors), as implemented by city or county planning departments, city or county building departments and air districts. Whether permits are required depends on the current zoning ordinance governing the proposed project site, the DG project sponsor, and the specifics of the DG project, including its size and technology type. Developers of DG facilities may apply for all required permits at the same time. Usually, though, a Developer gets air permits first, then land-use approvals, such as conditional use permits, and finally building permits.

Air permits are the first permits sought because air district requirements influence equipment selection. Once the DG equipment has been selected, the land-use approval process can begin. Local governments must know what makes and models of equipment will be installed to evaluate potential significant environmental impacts (e.g., noise and aesthetics) and to specify mitigation measures. Building permits are sought last because construction plans must incorporate all project changes required by the local government planning authority to mitigate environmental impacts.

CEQA Review and Land-Use Approvals

Local governments typically conduct CEQA reviews as part of the land-use-approval process. The land-use approval process may involve a request to rezone land to allow a distributed generation facility installation. Or it may involve a request for a conditional use permit. The investigation found that conditional use permitting is likely the most common type of land-use approval sought by DG facility developers. A DG project may require both land-use approval and an air permit. CEQA review is required if the project must have either land-use approval or an air permit. In situations where the DG project requires both, the local planning department typically serves as lead agency, coordinating its environmental review with other agencies. If only an air permit is required, then the air district assumes the lead agency role under CEQA.

The most basic steps of the environmental review process are the following:

1) Determine if the activity is a defined as a project subject to CEQA.

2) Determine if the project is exempt from CEQA.

3) Perform an initial study to identify the environmental impacts of the project and determine whether the identified impacts are defined as significant.

Based on its findings of significance, the agency prepares one of the following environmental review documents:

1) Negative Declaration if it finds no significant impacts,

2) Mitigated Negative Declaration if it finds significant impacts, but the developer revises the project to avoid or mitigate those impacts, or

3) Environmental Impact Report (EIR) if it finds significant unmitigated impacts.

Required Building Permits

Building permits are required for DG projects including equipment replacement, as an addition in an existing building, or as a component of a new building. These permits are issued after a city or county building department has determined that the permit package is complete, the project complies with all applicable building codes, and the project has received all other required approvals (e.g., conditional use permits and air district permits). During construction, the building department staff conducts field inspections to ensure that the project follows the approved plan. The building permit process is not subject to CEQA review or the time limits imposed by the Permit Streamlining Act. A key variable in building-permit timing is the type of construction. Retrofitting an existing building with DG will be simpler, in most cases, than permitting DG facilities in new construction.

Local jurisdictions enforce the California Building Standards Code which embodies the California Building, Electrical, Mechanical, Plumbing and Fire Codes. Because of local amendments, these codes may differ among jurisdictions. Building officials in the Bay Area, Los Angeles and San Diego are working to reduce the number of local amendments so that they can enforce building codes within their jurisdiction in a uniform manner.

The California Building Standards Code requires emergency or stand-by power in specific classes of residential, commercial, industrial and institutional buildings. Battery systems may supply emergency power to small electrical loads, such as exit lighting, but larger electrical loads need emergency generators. The California Electrical Code requires that emergency generators have an on-site fuel supply capable of powering emergency electrical loads for a specific number of hours. Natural gas supplied by the local gas utility is not an acceptable fuel source because deliveries may be interrupted during emergencies, such as earthquakes. For this reason most emergency generators run on diesel fuel. The California Electrical Code requirements for on-site fuel supply may conflict with future California Air Resources Board (CARB) efforts to set emission standards for DG facilities if the standards are achievable only by using natural gas.

Required Air Permits

Distributed generation facilities that burn fuel may be required to obtain air permits if equipment size or total projected emissions will exceed thresholds set by the air district. Air permitting requirements vary throughout California due to regional differences in air quality. Air districts in regions designated as non-attainment under the California or federal Clean Air Act may require DG projects to install Best Available Control Technology (BACT) and to purchase emission offsets. The air permitting process is typically three months but BACT determinations and efforts to secure offsets can delay the process. Air districts are concerned about the proliferation of fossil-fueled DG when the potential impacts on regional air quality and public health are not yet addressed in their air quality attainment plans. Emission rates from fossil-fueled DG are higher than those of large central station power plants, and their emissions are usually released near ground level, causing greater local impact on ambient air quality conditions. To justify their investment in DG, Electricity Producers tend to run base-loaded and peak-loaded DG equipment when electric rates are highest, during summer peak demand—just when local air quality is worst.

The use of emergency diesel generators in these circumstances is especially problematic because they emit high levels of NOx, particulates and toxic pollutants. These emissions are linked to asthma, lung disease, increased mortality rates and cancer. Communities may be at risk if diesel generators are deployed in greater numbers and used in other than emergency back-up modes.

Air district and DG equipment representatives agree that establishing uniform emission standards and certification programs for DG equipment would help to streamline air permitting. Equipment manufacturers, however, did not want emission standards set as low as central station BACT because emission controls are very costly for small-scale electrical generation.

The need for local pollution control and demand reduction do partially conflict. CAL-ISO and local air districts are now working together to better understand each other's needs and program operating criteria. Some local jurisdictions are being asked to permit new or enlarged emergency diesel generators to provide critical peak electricity to help prevent electricity outages for the next two to three years until new central station power plants come on line.

Some of the difficulties of DG air permitting are resolved in a recently passed California Senate bill, SB 1298. The law, now called Chapter 741 of the Statutes of 2000, requires CARB to issue permitting or certification[52] guidance to air districts on the generation technologies subject to air district permitting requirements. It also requires CARB to adopt uniform emission standards which reflect best performance achieved in practice for DG equipment that is exempt from air district permitting requirements. Once certification programs are in place statewide, all DG equipment must be certified or permitted before use or operation.

3.1 CEQA Review and Permit Streamlining Project Approach

In response to the CPUC request, the Energy Commission opened an investigation OII 99-DIST-GEN (2) to consider whether local government agencies can use a streamlined process to address CEQA issues in reviewing DG facilities. Under this order, the Commission's Energy Facility Siting and Environmental (Siting) Committee was designated as the lead for this work. In addition to meeting the needs of the CPUC's OIR, the Energy Commission's investigation considered permit streamlining for local land-use permitting, building permitting and air permitting. The Siting Committee conducted two public meetings and two local government surveys to solicit public comments about DG-related CEQA and permitting issues.

3.1.1 Siting Committee Workshop

The first public meeting was a Committee workshop on April 20, 2000. The Energy Commission staff sought to include local agencies in the workshop process. In addition to inviting approximately 140 parties on the CPUC R.99-10-025 service list, the staff distributed the workshop notice, along with a cover memo explaining the workshop notice and its potential relevance to their work, to about 1,200 State of California and local governmental entities. The meeting was broadcast over the Internet. The comment period was extended through May 5, 2000 to receive additional written comments related to the scoping questions and workshop discussions.

3.1.2 Workshop Report

In June 2000, the Commission staff reviewed the workshop materials and written comments to identify the key issues, potential solutions for an expedited CEQA review and local jurisdiction permitting, and published a Workshop Report, which contained summaries of this information.

The Workshop Report included background information about the CEQA review process and the three permitting processes. Besides posting it to the Commission website, copies of the Workshop Report were mailed to the CPUC, workshop attendees, all who are participating in the CPUC's DG proceeding, and local jurisdictions, including pollution control officers, planning managers and permit engineers for each California air district, and planning and community development directors and the chief building officials of all California cities and counties.

3.1.3 Local Government Surveys

The Workshop Report mailings to cities and counties included a survey to collect feedback about current DG permitting activities and local government interest in receiving technical assistance or training to facilitate DG permitting in the future. Different surveys were sent to city and county planning directors and to city and county building officials. As of October 2000, one hundred forty-three local jurisdictions have responded.[53]

3.1.4 Siting Committee Hearing

On September 7, 2000, the Siting Committee held a hearing to allow public comment on the Workshop Report. In addition to a staff-prepared summary of the Workshop Report's contents, Dorothy Rothrock of the California Manufacturers and Technology Association presented information on AB 1298. Following these presentations, the Committee heard comments from representatives of CARB, air districts, renewable energy advocates, DG consultants, local government and large energy consumers.

3.1.5 Siting Committee Report

The Siting Committee published a Committee Report on Distributed Generation: CEQA Review and Permit Streamlining[54] and distributed copies to the CPUC and a Notice of Availability to interested parties. The Committee Report was adopted by the Commission at its December 20, 2000 Business Meeting.

3.2 CEQA Review and Permit Streamlining Project Outcomes

The purpose of the CEQA Review and permit streamlining task of the OII was to identify barriers and propose solutions for each of the three areas of concern. From the approaches described in section 3.1 above, the Commission distilled barriers and solutions in each area into matrices. Other outcomes are also described below.

3.2.1 Outcome of Objective-1e: Identify barriers to DG in the CEQA Review and Land-Use Approval process and produce recommendations for removing or mitigating those barriers.

3.2.1.1 The CEQA Review Process

The following Table 1 summarizes the steps in the CEQA and Land Use Review process.

Table 3. Land-Use Permitting and CEQA Review Process

Step	*Land-Use Permitting/CEQA Review Actions*
1	Informal Consultation/Preliminary Review (Optional elsewhere)
2	Application submitted
3	Agency conducts Initial Study
4	Project information distributed to appropriate agencies and neighborhood groups for their review and comment
5	Project reviewed by the planning staff
6	Determine which environmental document to prepare (Notice of Exemption, Negative or Mitigated Negative Declaration, Environmental Impact Report)
7	Planner receives comments and schedules any necessary follow-up meetings
8	Environmental review completed
9	Planner schedules project for appropriate public hearing
10	Public Notices mailed to surrounding property owners
11	Planner prepares the staff report
12	Project is heard at the public hearing held by the Planning Commission (or Zoning Administrator)
13	Appeal Period (10 days)
14	If required, project is heard at a public hearing held by the City Council (or Planning Commission) or County Board of Supervisors

3.2.1.2 Existing Exemptions and Streamlining Efforts

Some DG is already exempt from CEQA. Some streamlining efforts are already underway. Review time for non-exempt DG can be reduced from one year to six months for DG which avoids or mitigates significant effects on the environment. Table 4 summarizes issues of applicability, exemption and streamlining.

Table 4. Outcome Summary, CEQA and Land-Use Approval

CEQA Review & Conditional Use Permit Applicability	***Exemptions from Process***	***Potential Streamlining Opportunities for Non-exempt DG Projects***
• When a DG developer applies for a building permit, the project is also reviewed by the jurisdiction's Zoning Administrator to ensure that the "proposed use" complies with all provisions of the zoning ordinance for that parcel of land or building. • If the Zoning Administrator determines that the project is a change of use, no building permit shall be issued until the Zoning Administrator performs a new zoning conformance review. If necessary, the project developer may need to request a conditional use permit (CUP) or zoning change. A CEQA review must be conducted before the local jurisdiction may approve a CUP or zoning change, because these approvals are "discretionary" acts.	**CEQA Statutory Exemptions** • Ministerial acts of local government, such as issuing building permits, are CEQA exempt. **CEQA Categorical Exemptions** • Cogeneration facilities at existing industrial, commercial and institutional sites, which meet specific air quality and other criteria are CEQA exempt. • Existing facilities, including facilities used by both investor and publicly-owned utilities "to provide electric power…" are CEQA exempt, provided the DG addition is not a new "use" of the existing site. • New construction or conversion of small structures, such as "small new equipment and facilities in small structures" are CEQA exempt. • Replacement or reconstruction, such as "existing utility systems and/or facilities involving negligible or no expansion in capacity…" are CEQA exempt. **Conditional Use Permit Exemptions** • If the DG project is an allowed use (conforms with local zoning ordinance), then no conditional use permit is required. "Accessory use" to a main use may also be allowed without a use permit.	• Update General Plan, zoning ordinance indicating where different types and sizes of DG are either allowed, require permits or zoning changes, or are prohibited. Clarify when DG is a "change in use." • Prepare model ordinance for types of DG. • Develop lists of DG projects that local governments may encounter that are exempt from CEQA. • Expand categorical exemption for cogeneration to other types of DG. • Set "thresholds of significance" for the environmental effects of DG projects. • Provide "best practices list" of mitigation measures for specific types of DG. • Revise project to avoid or mitigate environmental impacts, so that mitigated declarations can be prepared, rather than EIRs. • Provide the planning staffs with DG technology descriptions and environmental profiles. • Provide public education materials re: DG for developers to use at public hearings. • Encourage and help planning agencies to prepare a program or master EIR, to address the cumulative air quality impacts of combustion- type DG.

3.2.1.3 Barriers and Solutions Outcome

The outcome of the search for barriers and solutions for CEQA Review and Land-Use Permitting are summarized in Table 5.

Table 5. CEQA Review/Land-Use Permitting Issues and Potential Solutions

Issues / Problems	*Potential Solutions*	*Rationale*
CEQA Applicability		
• It is necessary to clarify the definition of "use" to determine when CEQA review and land-use permits apply.	• Provide guidance/legal interpretation of types of projects that would not be exempt from CEQA and that would require, at the very least, a negative declaration.	•Consistent agency interpretation of CEQA applicability provides certainty for DG project developers to minimize project delays.
• Relatively environmentally benign DG technologies and projects may undergo unnecessarily lengthy CEQA review and use permitting.	• Create/legislate a "categorical exemption" from CEQA for certain DG technologies.	• Encourages lower and non-emitting DG technologies where CEQA review may be relatively minimal.
• Insufficient information is provided by the developer for agencies to determine CEQA applicability.	• Develop a template for agencies to conduct their environmental impacts evaluation of a DG project	• Developers can provide sufficient information to agencies based on the agencies' template for project evaluation.
DG Technology Knowledge		
• Local planners and regulatory agencies do not have sufficient information to readily evaluate a project under CEQA and issue the necessary approvals.	• Develop a DG technologies and environmental profiles database for agencies to conduct their review and to identify possible mitigation measures and other conditions of approval.	• Technology specific information provides the starting point for agency and public evaluation of environmental impacts and mitigation measures, where applicable.
• Local communities may not want a DG project near them.	• Initiate discussion of the community's issues early on in project development.	• Avoids need for "damage control" during the public review process.
• Local communities may raise the issue of environmental justice.	• Initiate and conduct coherent communication among project developers, the public and agencies.	

Issues / Problems	*Potential Solutions*	*Rationale*
Specific Agency Standards and Policies • Current local land use policies and zoning may not readily allow DG. • The review process and applicable standards differ from region to region. • There are multiple agencies involved in DG project approval; agencies' requirements may compete or conflict. • It is unclear whether, and how, cumulative impacts may be addressed.	• Inform local elected officials about DG and encourage DG's recognition in general plans, et cetera. • Create standards for specific technology groups. • Provide/Use a consolidated set of siting requirements and involved agencies.	• Land use planning that accommodates DG project development minimizes the need for amending plans, the need for undergoing additional CEQA review, and the lengthy approval procedures. • Technology specific standards will minimize developers' guesswork for approvable projects. • Guidance for approval process will facilitate the introduction of DG technologies so vendors can design equipment that meet the standards.

3.2.2 Outcome of Objective-2e: Identify barriers to DG in the building permitting process and produce recommendations for removing or mitigating those barriers.

3.2.2.1 Building Permit Process

Building codes provide minimum standards for the protection, safety, and welfare of the public, property and the environment. They are not intended to limit the appropriate use of alternate materials, appliances, equipment, or methods of design or construction that are not specifically prescribed by the code. If the local building official determines that the proposed alternative is equivalent to that prescribed in the code, then the alternative can be used. The California Building Standards Code (CCR, Title 24) applies to all buildings and structures in the state. The following parts of the Code are relevant to DG installations:

- California Building Code (general building design and construction requirements, including fire-and life-safety and field inspection provisions);
- California Electrical Code (technical requires for all electrical power supplies);
- California Mechanical Code (mechanical standards for the design, construction, installation, and maintenance of heating, ventilating, cooling and refrigeration systems, incinerators, and other heat-producing appliances);
- California Plumbing Code (requirements for natural gas pipeline additions);
- California Fire Code (requirements for on-site fuel storage).

3.2.2.2 Existing Exemptions and Streamlining Efforts

DG projects are exempt from building permits if the entity conducting the project has been specifically exempted in the State Building Standards Code or Government Code of Regulations. All others must obtain permits, and streamlining is a necessity.

Table 6. Outcome Summary, Building Permitting

Building Permit Applicability	***Exemptions from Process***	***Potential Streamlining Opportunities for Non-exempt DG Projects***
• All privately developed new construction projects, including those with DG equipment, must obtain building permits. • Depending on the nature of the DG project, the following permits may be required: - Electrical - Plumbing - Mechanical - Building - Fire • DG installations in existing buildings must obtain building permits if they involve building alterations or additions, including new electric circuits, re-wiring, new or replacement gas lines.	• California Government Code exempts "local agencies" from obtaining local jurisdiction building permits. • State-owned buildings are exempt from obtaining building permits, but their DG projects must still comply with the California Building Standards Code. • Article 089-4 of the California Electrical Code exempts "installations under the exclusive control of electrical utilities for the purpose of …generation of electrical energy…" Electric utilities, therefore, do not need to obtain electrical permits for DG installations, which they will own, operate and maintain.	• Reduce the number of local amendments to the California Building Standards Code and to work together on uniform interpretations of the Code. • Develop DG equipment test protocols for use by certification laboratories. • Obtain UL or other nationally recognized testing lab certification for DG products. • Train building department staffs how to check plans for DG projects (what codes apply, what project design details to require, how to interpret codes). • Train building department field inspectors how to inspect DG projects. • Develop and use standard permit application package for "cookie cutter" DG projects.

3.2.2.3 Barriers and Solutions Outcome

The outcome of the search for barriers and solutions for building permitting are summarized in Table 7.

Table 7. Building Permitting Issues and Potential Solutions

Issues / Problems	***Potential Solutions***	***Rationale***
DG Technology Knowledge • The local building department staff may be unfamiliar with a DG technology. DG developer must spend time educating the "front desk" staff. • Building department field inspectors are not familiar with inspection protocols for certain technologies.	• Develop a standardized building permit submittal application package (e.g., PV systems). Use California-registered professional engineer to review plans. • Provide targeted training for field inspectors. Present new technology using agency's terms and interests: how system meets codes, fire ratings, etc.	• Standardized application packages for DG technologies provides certainty regarding the necessary technology and project parameters. • Training for inspectors will minimize delays in project approvals.
Siting Requirements and Agency Procedures • There is not a comprehensive resource(s) for identifying permits and approvals that must be secured for DG project development. • Existing California Environmental Protection Agency website (CalGOLD) offers permit assistance to many types of businesses but does not have a business type for DG. So project developers cannot use this reference.	• Publish a Guidebook for building permit departments (the regulatory staff) on approving permits to readily deploy DG technologies. • Develop specific guidance document/tool/resource for developers to identify necessary agency approvals, applicable regulations, and processing fees. • Compile/Develop a "best practices" list as it relates to licensing various DG projects: - Has any similar project been through the same processes? - What timeframes did they experience? • Work with CalEPA's CalGOLD website providers to disseminate information to DG developers on permitting requirements.	• Help agencies develop/conduct their own DG approval processes more efficiently. • Enable DG project developers to spend less time and expense obtaining approvals. • Set the proper expectations about the time and effort that will be required to obtain approvals. • The existing CalGOLD website can be modified to include DG as a business type.
DG Specific Agency Standards and Policies • Local codes may not address DG technologies. • Applicable standards, such as fire codes, differ from region to region.	• Extend building codes to cover energy use of DG, encouraging combined heat and power applications. • Modify building codes for optimizing sizing and installation standards. • Create standards for specific technology groups. • Have a nationally recognized testing laboratory, such as Underwriters' Lab, test DG for certification. Design for "plug and play."	• Technology specific standards will minimize developers' guesswork for approvable projects. • Specific standards and policies for DG technologies will allow vendors to design equipment that meet the standards.

3.2.3 Outcome of Objective-3e: Identify barriers to DG in the air permitting process and produce recommendations for removing or mitigating those barriers.

3.2.3.1 Air Permit Process

Depending on the size of a DG technology and its emissions profile, the air permitting process may be relatively straightforward or may involve several technical evaluations. In non-attainment areas the permitting process may include evaluating whether additional emission controls are necessary to reduce emissions, obtaining emission reduction credits (offsets)[55] and evaluating potential air toxic emissions impacts.

Permit applications typically include completing and submitting district form(s), estimating emissions, providing equipment specifications, an operations plan, site plan and facility map, paying fees, and providing the results of various technical analyses. The air district staff review the air permit application, evaluate whether BACT applies or air toxics modeling (or other air quality analyses) is needed and determine if emission reduction credits are required. BACT is an emission limitation taking into account energy, environmental and other economic impacts, and costs. The modeling analyses estimate the impacts to nearby residents and businesses. In California emission reduction credits (if needed) must be permanent, quantifiable, real, surplus and enforceable, as defined in the federal Clean Air Act. Construction typically cannot begin until the air district has completed its evaluation and has issued an authority to construct.[56] After equipment has been installed, emissions testing may be required.

Air districts have relatively straightforward permitting processes for diesel standby or emergency generator engines. These engines are generally limited to annual hours of operation ranging from 52 to 200 hours. Allowable annual hours vary from district to district and provide time for engine readiness testing and maintenance. The criteria for operating these engines are specific to actual power outages and typically do not apply to distribution grid support. However, it should be noted that some air districts broadly interpret their regulations to provide for the flexibility of operating these engines as peak shavers within an allowable 200 hours per year. CARB is in the process of developing final permit guidelines for new and existing diesel engine generators operating as standby, peak or baseload units.

3.2.3.2 Existing Exemptions and Streamlining Efforts

DG equipment which does not emit air pollutants does not need to obtain air permits. DG equipment with air emissions below specific permitting thresholds (set by the district) are exempt from air permitting. For example, fuel cells do not need air permits when they are installed in South Coast AQMD. Some energy storage batteries emit toxic air contaminants and are not exempt from obtaining air permits.

Table 8. Outcome Summary, Air Permitting

Air Permit Applicability	***Exemptions from Process***	***Potential Streamlining Opportunities for Non-exempt DG Projects***
All DG projects proposing to use technologies, which emit regulated air pollutants, as determined by the local air district.	• Some renewable energy technologies, such as solar photovoltaic, wind, hydro-electric are air-permit exempt. • Some local air districts may have exempted specific, low-emission fossil-fueled or biomass-fired DG equipment from obtaining air permits. • Typically, exemptions are based on equipment capacity, heat input or emissions.	• Set uniform emission standards and certify DG equipment which meets the specified emission or performance standards. • Provide accelerated permitting for certified DG equipment. • Provide guidance to the air district staffs on how to make BACT determinations. • Assist DG equipment obtain emission reduction credits.

3.2.3.3 Barriers and Solutions Outcome

Representatives from air districts and the CARB attended the Energy Commission's public meetings on DG, CEQA review and permit streamlining. Agencies shared their concerns regarding the potential increased use of fossil-fueled DG technologies that may have public health impacts, with specific emphasis on diesel standby generators that may be deployed for peak shaving. The issues or problems that were raised include the following:

- Currently air districts exempt certain emergency fossil fuel-fired DG installations from their permitting processes, but the cumulative impacts to the environment and public health from increasing numbers of installations in a region may be significant;
- Air quality requirements differ from district to district;
- Emissions from small fossil fuel-fired DG technologies are not as low as central power plant emissions on a pounds per megawatt-hour (lbs/MWh) basis;
- Existing emergency diesel engines will be used for peak shaving and emit toxic air pollutants;
- The air quality impacts from DG technologies are dependent on the type of equipment, fuel, and application.

The outcome of the search for barriers and solutions for air permitting are summarized in Table 9.

Table 9. Air Permitting Issues and Potential Solutions

Issues / Problems	*Potential Solutions*	*Rationale*
DG Specific Agency Standards and Policies • Air quality control technology requirements do not account for energy benefits, e.g., fuel efficiency. • Emission standards and control requirements differ from region to region. • Manufacturers must make different products to sell in different parts of California or have limited markets.	• Use output-based emission standards, e.g., lb/MW-hr, develop uniform, well-defined BACT standards. • Create uniform environmental performance standards for fossil fuel-fired technologies. • Develop pre-certification program for DG units for permit streamlining or exemptions. • Develop an accelerated permitting program for low-emitting DG technologies and applications.	• Combined heat and power recognized for efficiencies. • Uniform, output based emission standards provides incentive for efficient technologies and pollution prevention goals. • Applicant obtains accelerated or over-the-counter permit without an air district CEQA review. • Provides certainty of air district emission standards and process. • DG products at "appliance level" are candidates for precertification based on emission test results (e.g., similar to natural gas space and water heaters). • Exempt DG can avoid air permit paper work and delays.
Regional Emissions Impact • Fossil fuel-fired units emit air pollutants that have environmental and public health impacts • DG stacks have near-ground impacts and are likely to be near populated areas, e.g., near load centers, versus remote central power plant impacts • Cumulative impacts from multiple DG units may delay district attainment.	• Fossil fuel-fired DG units that are not exempt from permits must be evaluated for BACT. • Fund advanced DG technologies with progressively low emissions, e.g., natural gas fired spark ignition engines, DOE program on advanced gas recip engines. • Air pollution prevention program targeted toward DG, explicitly addressing environmental performance of DG technologies. • Address aggregate impacts in attainment planning and account for energy benefits.	• Advanced DG technologies could compete with larger natural gas-fired combined cycle plants. • Attainment planning, which incorporates potential growth of DG industry could minimize stifling of DG unit deployment.
Diesel Engine Operation and Emissions • Exhaust from engines contains air toxic emissions. • Standby engines are likely peak shaving units running on peak days, e.g., hottest, smoggiest days of the year. • Some emergency engines have minimal to no controls.	• Develop permit requirements for new and existing non-emergency diesel engines; this includes particulate controls to minimize air toxic impacts. • Develop criteria for engines serving peak needs to provide grid support.	• Creates market for new generators that use natural gas as well as add-on and retrofit controls. • Peak shaving minimizes energy costs and the upgrade of distribution lines.

3.3 CEQA Review and Permit Streamlining Conclusions and Recommendations

3.3.1 Conclusions

3.3.1.1 Can certain types of DG qualify for exemption from CEQA?

Yes. Certain types of DG are exempt from CEQA. These include cogeneration facilities at existing facilities, which meet specific eligibility criteria. Other types of DG systems may also qualify for CEQA exemption if they fit into the following classes of CEQA-exempt facilities:

- Existing facilities (Class 1),
- Replacement or reconstruction (Class 2), and
- New construction or conversion of small structures (Class 3).

3.3.1.2 Can certain types of DG qualify for some form of streamlined CEQA review?

Yes. The CEQA review process for negative declarations and mitigated negative declarations is limited to six months while the process for EIRs is one year. The types of DG which qualify for negative declarations are those which avoid or mitigate significant effects on the environment.

For DG facilities that undergo some form of CEQA review, information regarding DG technology characteristics, potential environmental impacts (e.g., aesthetics, noise, air, hazardous materials) of the DG technologies, and standard mitigation measures would help in the review process.

Several air districts raised the concern that cumulative impacts may be a concern. Cumulative impacts of many insignificant DG projects may cause a local jurisdiction to require a full EIR for an individual DG project, even if its incremental impacts are small. A Planning Department representative from the City of Roseville noted that cumulative impacts of insignificant DG projects would not likely cause a local jurisdiction to require a full EIR for each project. The determination of whether a full EIR is necessary would be based on an agency's interpretation of significance.

One way to address the issue of cumulative impacts is to prepare a program or master EIR. The results of such a program EIR could be useful to local agencies with land-use planning or air quality management responsibilities in the processing of negative declarations for qualifying DG technologies. Most local jurisdictions are not interested in this option.

3.3.1.3 Can certain types of DG technologies qualify for a streamlined land-use permitting process?

Yes. The land-use permitting process could be streamlined by developing draft model ordinances for categories of DG technology and provide these draft ordinances to local governments for possible adoption. Educating local jurisdictions and the public, and drafting model ordinances help agencies better understand how DG fits in the regulatory environment and whether new ordinances are appropriate.

3.3.1.4 Can certain types of DG qualify for exemption from building permits?

Most construction projects will require building permits, unless the entity conducting the project has been specifically exempted from obtaining building permits in the State Building Standards Code or Government Code of Regulations.

Local agencies, such as SMUD, are exempt from obtaining building permits for constructing electric generation, storage, and transmission facilities. State-owned buildings under jurisdiction of the State Fire Marshal are exempt from obtaining building permits, but are required to obtain plumbing, mechanical and electrical permits. Regulated electric utilities are exempt from obtaining electrical permits.

3.3.1.5 How can the building permit process be streamlined for DG?

Suggested strategies to streamline the building permit process include the following:

- Providing educational services to the staffs of building departments;
- Obtaining a UL or other nationally recognized testing laboratory's listing for the DG equipment or device;
- Encouraging local jurisdictions to work together to reduce the number of local amendments to the State Building Standards Code, as was done by the Silicon Valley Uniform Code Program and as is underway in Los Angeles and San Diego;
- Developing and using standardized permit application packages;
- Providing permit assistance to DG project developers, which helps them understand what approvals they must obtain.

More than half of the building departments responding the Energy Commission's survey indicated that the following information services would help them conduct their plan checking and field inspections of DG projects more efficiently:

- Written guidelines of which building codes apply to which types of DG projects;
- Regional training on building code applicability and interpretation for each type of DG projects;
- An inspection checklist for specific types of DG;
- Regional training in how to inspect specific types of DG installations.

3.3.1.6 Can certain types of DG qualify for exemption from air permits?

Yes. DG equipment which does not emit air pollutants does not need to obtain air permits. Specifically, some renewable energy equipment (e.g., wind, photovoltaic and hydroelectric) are exempt from air permitting.

3.3.1.7 How can the air permit process be streamlined for DG?

Strategies to streamline the air permitting process include the following:

- Develop (statewide) uniform emission standards;
- Create an expedited permit process for pre-certified DG equipment;

- Create an expedited permit process for the lowest-polluting equipment;
- Assist DG projects in obtaining emission reduction credits, when needed.

3.3.2 Recommendations

The following recommendations on CEQA and permit streamlining have been adopted by the Energy Commission. Three general recommendations (3.3.2.1- 3.3.2.3) are followed by three specific recommendations (3.3.2.4 - 3.3.2.6).

3.3.2.1 Clarify Energy Commission policy regarding Distributed Generation.

The Energy Commission should articulate in policy why it believes that qualifying DG projects should receive special treatment by the State or local jurisdictions that results in streamlined CEQA review and permit processing. The Energy Commission recommends that only the cleanest DG technologies, such as solar PV and fuel cells, receive permit-streamlining support.

3.3.2.2 Clarify Energy Commission's role in CEQA review and permit streamlining.

The Energy Commission should seek to define its role, if any, in facilitating DG CEQA review and permitting. The Commission does not seek to replace local jurisdiction siting and permitting authority regarding DG facilities. Other State agencies already provide permit streamlining assistance to private developers and local governments, including the California Environmental Protection Agency (Cal-EPA) Permit Assistance Centers, the California Trade and Commerce Agency's Office of Permit Assistance, and the CARB. The Energy Commission's unique contribution could be its technical knowledge of various DG technologies and how to mitigate environmental impacts of electric generation facilities.

3.3.2.3 Any technical assistance provided by the Energy Commission should be targeted.

Any technical assistance services should be targeted to local governments, rather than to private DG developers. This approach would enable the Energy Commission to maintain its neutrality regarding the acceptability of individual DG projects while facilitating DG project deployment. Three levels within local government should be targeted for services: elected officials, planning department staff and building department staff. Building department services should be targeted for plan checkers and field inspectors.

3.3.2.4 Recommendations for Objective-1e: Streamline the CEQA Review process.

Funding should be made available to develop:

- Lists of DG projects that are exempt from CEQA;
- Thresholds of significance in key environmental issue areas, including air quality, noise and aesthetics;
- Standard mitigation measures for the types of DG technologies which might cause significant environmental impacts in air quality, noise and aesthetics;
- A master Environmental Impact Report (EIR) for gas turbines and diesel generators to address the cumulative air quality impacts from these projects.

3.3.2.5 Recommendations for Objective-2e: Streamline the Building Permitting process.

Funding should be made available to initiate a training and technical assistance program for assisting city and county building departments to perform plan checks and field inspections of DG technology.

3.3.2.6 Recommendations for Objective-3e: Streamline the Air Permitting process.

The Energy Commission should work with appropriate jurisdictions to:

- Develop statewide uniform emission standards.
- Create an expedited permit process for pre-certified DG equipment.
- Create an expedited permit process for the lowest-polluting equipment.
- Assist DG projects in obtaining emission reduction credits.

3.3.3 Benefits to California

General recommendation 3.3.2.1 benefits fuel cells, photovoltaic installations and certain other zero emissions prime mover technologies.[57] Typically these installations do not require CEQA or air permitting review. So the benefit is limited to assistance in the building permitting process.

Recommendation 3.3.2.2 would allow the Commission to share its knowledge of DG and electricity generating station siting with CEQA siting authorities. The Commission could fill the current knowledge gap about DG, lowering its barrier to entry.

Recommendation 3.3.2.4 CEQA exemption list, would allow DG developers to check quickly and easily see if their category of project were exempt. This would save the current time-consuming and redundant process of case-by-case determination. A list of thresholds of significance in key environmental issue areas, including air quality, noise and aesthetics would alert developers to possible difficulties in the CEQA Review process. A master Environmental Impact Report (EIR) for gas turbines and diesel generators would address the cumulative air quality impacts from these projects and obviate the need for or risk of case-by-case EIRs.

Implementation of recommendation 3.3.2.6 could facilitate DG air permitting. Both statewide emission standards and an expedited permit process for pre-certified DG are part of Chapter 741 of the Statutes of 2000 and are therefore being implemented now through a CARB-led multi-stakeholder group. Lowest-polluting equipment needs no air permit. This includes PV and fuel cells. DG manufacturers are also making interesting advances with no-NOx and low-NOx fossil- and renewable-fuel turbines and microturbines.

4.0 General Conclusions and Recommendations

4.1 Conclusions

The stock of in-state electricity generation units is insufficient to meet current demand. Market-based wholesale prices have been on average three times higher than capped retail prices. The situation has created an economic crisis caused by purchasing power at a tremendous loss. CAL-ISO issued its first Stage Three warning in December 2000, advising that there was less than 1.5 percent reserve electric capacity. In January and February 2001, it issued 32 Stage Three warnings in a row. The governor, the legislature and state energy officials are searching for solutions. DG can and should be a key component in the future of California energy supply. The primary mechanism for addressing the barriers to DG has been the CPUC's OIR effort, which called for Commission participation in the form of the OII. The OII Interconnection and permit streamlining efforts both delivered recommendations the CPUC which can hasten the day when DG becomes a more significant part of the solution to California's energy needs. The Interconnection effort, especially, exceeded the expectations of the OII by delivering a Revised Rule 21 which implements all of its recommendations as tariff. It was rapidly adopted by the CPUC both in its initial and final forms. The contractual arrangement that allowed the FOCUS team to assist the Commission in its OII should become a model for future Commission-led Investigations.

4.2 Recommendations

A post-implementation workgroup should be formed to further the work on Interconnection. With appropriate technical support and funding, this workgroup could ensure the success of the Revised Rule 21. Testing and Certification work, particularly, needs further advancement before any DG unit can be considered for Simplified Interconnection. The IRP, the Agreement form and the Application all need to be tested in the real world. DG systems operating in the field need to be monitored to see how they are interacting with the Distribution System in terms of reverse power flow, harmonics, flicker and adjacent customer impacts (where possible). The data need to be analyzed and the results communicated to the post-implementation working group, to the utility, to the DG developer and Applicant. Changes necessitated by real experience of using the Revised Rule 21 need to be made to ensure the relevance and usefulness of the Rule. Finally, the effort to implement Chapter 741 of the Statutes of 2000 needs to carry out its mandate to make air permitting more efficient for all DG.

4.3 Benefits to California

The FOCUS team successfully fulfilled the technical and economic performance objectives laid out in its workstatement. The team achieved 99 percent consensus on non-technical issues and 100 percent consensus on technical issues. The FOCUS team also outperformed its own tactical objectives, producing two more consensus PBIRs than expected and two extra cost-critical policy issues.

Table 10. Tactical Performance

Tactical Performance	w/o Contractor	w/ Contractor	% Gain
Estimated Consensus PBIRs[58]	18	48	167%
Actual Consensus PBIRs	18	50	177%
Estimated Cost-Critical Policy Issues	5	7	40%
Actual Cost-Critical Policy Issues[59]	5	9	55%

Cost-critical policy issues include: 1. Cost of initial study; 2. Cost of supplemental study; 3. Ability to negotiate multiple sites with EC; 4. Time of initial study; 5 Time of supplemental study; 6. Rule uniformity; 7. EC (utility) discretion; 8.Agreement form; 9. Application form. It is assumed that policy issues would weigh about twice as heavily as the PBIR solutions on a per-item basis, and that the workgroup, drawing on the work of Texas, could complete most of these on its own.

Section 2.3.3.2 above explains that cost figures for Interconnection of DG are estimates,[60] and not based on actual installations. These are the best available metric for the value of this project and the value of future work. An analysis is carried out below to show a comparison of the cost of interconnecting three different sizes of DG:

- Small DG – 0 to 199kW
- Medium DG – 200kW to 999kW
- Large DG – 1MW +

Under four different scenarios:

- Scenario 0 – Basecase Year 2000: No FOCUS contract or funded post-implementation effort; Unadjusted for technological improvement.
- Scenario 1 – End case Year 2006. No FOCUS contract or funded post-implementation effort; Adjusted for cost reduction due to technology improvement.
- Scenario 2 – End case Year 2006. With a FOCUS-I effort, but no funded post-implementation effort.
- Scenario 3 – End case Year 2006. With a FOCUS-I and a funded post-implementation effort.

The following table illustrates the situation. The Unadjusted Scenario-0 is a year 2000 baseline of estimated cost of Interconnection without any regulatory effort, that is, assuming that this FOCUS project had not been done and there was no change in costs due to technological advancement. The Adjusted Scenario-1 is an end case year after 7 years of technology improvement. Otherwise it is the same as Scenario-0. Scenario-2 shows the estimated end case 2006 costs after completion of this project, based on an assumption of successful completion of the objectives described in Sections 2 and 3 of this paper. Scenario-3 shows the estimated end case year 2006 after a second phase of this project, a funded post-implementation effort. Scenario-3 would put the recommendations included in this paper into practice. A functioning Certification process, accurate field monitoring and data analysis are the basis of the additional cost reductions.

Table 11. Cost by Size for Interconnecting DG Systems

	2000	2006	2006	2006	2006	2006
Strategic Performance[61]	Unadjusted Scenario-0	Adjusted Scenario-1	Scenario-2	Scenario-3	*Expected*[62] *% Gain*	*Actual*[63] *% Gain*
Less than 200kW	$125	$93	$73.50	$54	41.9%	41.2%
From 200kW – 1MW	$ 95	$69	$53.50	$38	44.9%	43.7%
Greater than 1MW, $/kW	$ 33	$28	$24.50	$21	25.0%	25.8%

Given the basecase year 2000 and the three end case years at 2006 (Scenario-1 through 3), it is possible to draw lines between to show average cost reductions during the interim years.[64]

Figure 2 shows how the estimated costs go down over time. The downward cost curve with no FOCUS effort is due to the likely decline in cost of Interconnection technologies (Adjusted Scenario-1). The FOCUS line shows the effect of work already completed to date. It is assumed that costs go down evenly between the basecase and end case years. The Scenario-3 line shows the additional benefit of carrying out the recommendations above. It assumes that the recommendations made in this paper are put into action by the end of 2003.

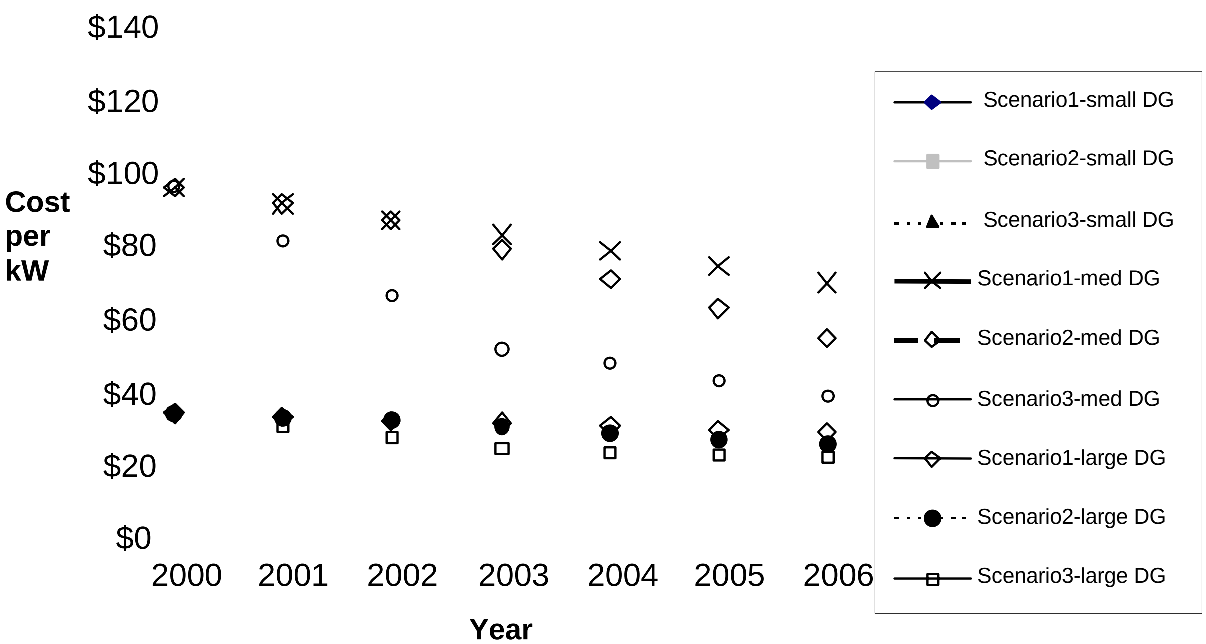

Figure 2. The Estimated Cost of Interconnection of DG

Comparing the estimated cost per kW reductions of Scenario-2 with the cost reductions from Scenario-3 shows significant cost reductions of the latter path. Funding a post-implementation effort will create an additional reduction of Interconnection cost of 14.3 percent in the greater-than- 1MW size, 29 percent in the 0.2 to 1MW size, and 26.5 percent in the less-than-200kW size.

Glossary

Accredited, Nationally Recognized Testing Laboratory (NRTL)	A laboratory approved to perform the certification testing requirements.
Active Anti-Islanding Scheme	A control scheme installed with the Generating Facility that senses and prevents the formation of an Unintended Island.
Air Permitting	The process a source of criteria air emissions (those emissions covered by the Environmental Protection Agency's Clean Air Act Amendments of 1990) must go through in order to operate an emissions source. The local Air Quality Management District is usually the permitting agency.
Applicant	The entity submitting an Application for Interconnection.
Application	The standard form CPUC-approved document submitted to the Electrical Corporation for electrical Interconnection of a Generator with the Electrical Corporation.
Building Permitting	The process a developer of any structure must go through receive regulatory approval for construction. The county and/or municipality is usually the permitting agency.
CEQA Review	California Environmental Quality Act Review. CEQA is a State statute that requires State and local agencies to identify the significant environmental impacts of their actions and to avoid or mitigate those impacts, if feasible. State and local public agencies must comply with CEQA. Every development project, which requires a discretionary governmental approval will require at least some environmental review pursuant to CEQA, unless an exemption applies.
Certification Test	A test adopted by an Electrical Corporation that verifies conformance of certain equipment with CPUC-approved performance standards in order to be classified as Certified Equipment. Certification Tests are performed by NRTLs.

Certification; Certified; Certificate	The documented results of a successful Certification Testing.
Certified Equipment	Equipment that has passed the Certification Test.
Commissioning Test	A test performed during the commissioning of all or part of a DG system to achieve one or more of the following: 1) Verify specific aspects of its performance; 2) Calibrate its instrumentation; 3) Establish instrument or Protective Function set-points.
CPUC	The Public Utilities Commission of the State of California.
Customer	The entity that receives or is entitled to receive Distribution Service through the Distribution System.
Dedicated Transformer (DT); Dedicated Distribution Transformer	A transformer that provides Electricity Service to a single Customer. The Customer may or may not have a Generating Facility.
Distributed Generation (DG)	Electrical power generation by any means, including from stored electricity, that is interconnected to an Electrical Corporation at a Point of Common Coupling under the jurisdiction of the CPUC.
Distributed Generator; Generator (DG)	An individual electrical power plant (including required equipment, appurtenances, protective equipment and structures) that is capable of Distributed Generation.
Distribution Service	All services required by, or provided to, a Customer pursuant to the approved tariffs and rules of the Electrical Corporation.
Distribution System:	All electrical wires, equipment, and other facilities owned or provided by the Electrical Corporation by which an Electrical Corporation provides Distribution Service to its Customers.
Electrical Corporation (EC)	The entity that, under the jurisdiction of the CPUC, is charged with providing Electricity Distribution Service to the Customer.

Electricity Producer (EP)	The entity that executes an Interconnection Agreement with the Electrical Corporation. The Electricity Producer may or may not own or operate the Generating Facility, but is responsible for the rights and obligations related to the Interconnection Agreement.
Emergency	An actual or imminent condition or situation, which jeopardizes the Distribution System Integrity.
EPA	Environmental Protection Agency.
Field Testing	Testing performed in the field to determine whether equipment meets the Electrical Corporation's requirements for safe and reliable Interconnection
Generating Facility (GF)	All Distributed Generators that are included in an Interconnection Agreement.
Gross Nameplate Rating	The total gross generating capacity of the Distributed Generator as designated by the manufacturer of the Distributed Generator.
Host Load	Electrical power that is consumed by the Customer at the property on which the Generating Facility is located
IEEE	Institute of Electrical and Electronics Engineers
Initial Operation	The first time the Generating Facility is in Parallel Operation.
Initial Review	The review by the Electrical Corporation, following receipt of an Application, to determine the following: 1) If an Application qualifies for Simplified Interconnection; 2) If an Application can be made to qualify for Interconnection with supplemental review determining any potential additional requirements; or 3) If an Interconnection Study is required, the cost estimate and schedule for performing the Interconnection Study.
In-rush Current	The current drawn by the DG during startup.
Interconnection Agreement	An agreement between the Electrical Corporation and the Electricity Producer that gives each the certain rights and obligations to effect or end Interconnection.

Interconnection Facilities	The electrical wires, switches and related equipment that interconnect a Generating Facility to the Distribution System.
Interconnection Study	A study to establish the requirements for Interconnection of an Electricity Producer.
Interconnection; (Interconnected)	The physical connection of Distributed Generation in accordance with the requirements of these rules so that Parallel Operation with the utility system can occur (has occurred).
IPP	Independent Power Producer
IR	Interconnection Requirements
Island; Islanding	A condition on the Distribution System in which one or more Generating Facilities deliver power to Customers using a portion of the Distribution System that is electrically isolated from the remainder of the Distribution System.
CAL-ISO	The California Independent System Operator, responsible for the management of electrical power flow through California's electrical transmission network.
Line Section	That portion of the Distribution System connected to a Customer bounded by automatic sectionalizing devices or the end of the line.
Metering Equipment	All equipment, hardware, software including meter cabinets, conduit, etc. that is necessary for Metering.
Metering	The measurement of electrical power flow in kW and/or kWh, and, if necessary, kVAR at a point, and its display to the Electrical Corporation, as required by this rule.
Net Energy Metering	Metering for the mutual purchase and sale of electricity between the Electricity Producer and the Electrical Corporation pursuant to the net metering tariff approved by the CPUC.

Net Generation Metering	The Metering of the net electrical energy output in kW and kWh from a given Generating Facility. This may also be the measurement of the difference between the total electrical energy produced by a Distributed Generator and the electrical energy consumed by the auxiliary equipment necessary to operate the Distributed Generator. For a Distributed Generator with no Host Load and/or Section 218 Load, Metering that is located at the point of Common Coupling. For a Distributed Generator with Host Load and/or Section 218 Load, Metering that is located at the Distributed Generator bus after the point of auxiliary load(s) and prior to serving Host Load and/or Section 218 Load.
Net Metering	Where electricity at a point may flow in both directions, the measurement of the net, or the algebraic sum, of electrical energy in kWh, that flows through that point in a given time-interval. Net Metering typically uses two meters, or in some cases a single meter with two or more registers, to individually measure a Customer's electric deliveries to, and consumption of retail service from, the Distribution System. Over a given time frame (typically a month) the difference between these two values yield either net consumption or net surplus. The meter registers are ratcheted to prevent reverse registration. If available, a single meter may be allowed spin backward to yield the same effect as a two meter (or register) arrangement.
Net Nameplate Rating	The Gross Nameplate Rating minus the consumption of electrical power of the Distributed Generator as designated by the manufacturer(s) of the Distributed Generator.
Network Service	More than one electrical feeder providing Distribution Service at a Point of Common Coupling.
Non-Exporting	Designed to prevent the transfer of electrical energy from the EP to the EC.
Non-Islanding	Designed to detect and disconnect from a stable Unintended Island with matched load and generation. Reliance solely on under/over voltage and frequency trip is not considered sufficient to qualify as Non-Islanding.
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
P1547	IEEE workgroup formulating Interconnection standards

Parallel Operation	The simultaneous operation of a Distributed Generator with power delivered or received by the Electrical Corporation while Interconnected. For the purpose of this rule, Parallel Operation includes only those generators that are so interconnected with the Distribution System for more than 60 cycles.
PBIR	Performance-Based Interconnection Requirement
Periodic Test	A test performed on part or all of a DG system at pre-determined time or operational intervals to achieve one or more or the following: 1)Verify specific aspects of its performance; 2) Calibrate instrumentation; 3) Verify and re-establish instrument or Protective Function set-points.
Point of Common Coupling (PCC)	The transfer point for electricity between the electrical conductors of the Electrical Corporation and the electrical conductors of the Electricity Producer.
Point of Common Coupling Metering	Metering located at the Point of Common Coupling. This is the same Metering as Net Generation Metering for Generating Facilities with no Host Load and/or Section 218 Load.
Point of Interconnection	The electrical transfer point between an electrical power plant and the electrical distribution system. This may or may not be coincident with the Point of Common Coupling.
Power Purchase Agreement (PPA)	An agreement for the sale of electricity by the Electricity Producer to the Electrical Corporation.
Production Test	A test performed on each device coming off the production line to verify certain aspects of its performance.
Protective Function(s)	The equipment, hardware and/or software in a Generating Facility (whether discrete or integrated with other functions) whose purpose is to protect against Unsafe Operating Conditions.
Prudent Electrical Practices	Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Revised Rule 21	Attachment A to California Energy Commission Publication 700-00-014
Rule 21	A CPUC rule specific to each Electrical Corporation that describes the conditions of Distribution Service to Customers and includes provisions for charges related to Special Facilities and Interconnection Facilities.
Scheduled Operation Date	The date specified in the Interconnection Agreement when the Generating Facility is, by the Electricity Producer's estimate, expected to begin Initial Operation.
Secondary Network	A network supplied by several primary feeders suitably interlaced through the area in order to achieve acceptable loading of the transformers under emergency conditions and to provide a system of extremely high service reliability. Secondary networks usually operate at 600 V or lower.
Section 218 Load	Electrical power that is supplied in compliance with California Public Utilities Code (PU Code) section 218. PU Code 218 defines an “Electric Corporation” and provides conditions under which a generator transaction would not classify a generating entity as an Electric Corporation. These conditions relate to “over-the-fence” sale of electricity from a generator without using the Distribution System.
Short Circuit Contribution Ratio (SCCR)	The ratio of the Generating Facility’s short circuit contribution to the Electrical Corporation’s short circuit contribution for a three-phase fault at the high voltage side of the distribution transformer connecting the Generating Facility to the Electrical Corporation’s system.
Simplified Interconnection	Interconnection conforming to the minimum requirements under these rules, as determined by Appendix A.
Special Facilities	Those facilities installed at the Electricity Producer’s request, which the Electrical Corporation does not normally furnish under its tariff schedule; or a pro rata portion of existing facilities requested by the Electricity Producer, allocated for the sole use of such an Electricity Producer, which would not normally be allocated for such sole use.

Stabilization; Stability	The return to normalcy of an Electrical Corporation Distribution System, following a disturbance. Stabilization is usually measured as a time period during which voltage and frequency are within acceptable ranges.
Starting Voltage Drop	The percentage voltage drop at a specified point resulting from In-rush current. The SVD can also be expressed in volts on a particular base voltage, (e.g., 6 volts on a 120-volt base, yielding a 5 percent drop).
System Integrity	The condition under which a Distribution System is deemed safe and can reliably perform its intended functions in accordance with the safety and reliability rules of the Electrical Corporation.
Telemetering	The electrical or electronic transmittal of Metering data on a real-time basis to the Electrical Corporation.
Type Test	A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.
Unintended Island	The creation of an island, usually following a loss of a portion of the Distribution System, without the approval of the Electrical Corporation.
Unsafe Operating Conditions	Conditions that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of System Integrity or operation outside pre-established parameters required by the Interconnection Agreement.

Endnotes

[1] All capitalized terms are included in the Glossary. Thus "Interconnection" is capitalized throughout.

[2] DG may stand either for Distributed Generation or Distributed Generator. Context will make clear which is intended. The terms "DG equipment" or "DG facilities" or "DG unit(s)" usually indicates a substitution for Distributed Generator; "DG" by itself usually means Distributed Generation. Although the workgroup avoided this collapsed coinage, it is in such widespread use in the "DG community" that we have become adept at the substitution.

[3] See Section 2.2.5.2 for a listing of the 50 consensus PBIRs.

[4] Cost-critical policy issues are: 1.Cost of initial study; 2. Cost of supplemental study; 3. Ability to negotiate multiple sites with EC; 4. Time of initial study; 5 Time of supplemental study; 6. Rule uniformity; 7. EC (utility) discretion; 8.Agreement form; 9. Application form It is assumed that policy issues would weigh about twice as heavily as the PBIR solutions on a per-item basis, and that the workgroup, drawing on the work of Texas, could complete most of these on its own.

[5] Workstatement for contract # 700-99-010, page A-1.

[6] The Basecase is derived for systems <200kW as an average of a 50kWmicroturbine, a 100kW gas engine and a 200kW fuel cell; the figure for 200kW – 1MW is based on an 800kW gas engine; the figure for <1MW is based on a 5MW gas turbine and a 25MW gas turbine. All figures are from *Market Assessment for Combined Heat and Power Systems in California*, California Energy Commission, 1999; and from private conversation with Mike Edds.

[7] All currency totals are $ / kW.

[8] Expected gain is the difference between Scenario-1 and Scenario-3 as a percentage of the total cost of Scenario-1; Actual gain is the difference between Scenario-0 and Scenario-2 as a percentage of the total cost of Scenario-0.

[9] See endnote 7.

[10] CEQA review, building and air permitting are not within CPUC's jurisdiction, so they will not act on these recommendations.

[11] See the section on Market Potential in the California Energy Commission Publication 700-00-009, "Market Assessment of Combined Heat and Power in the State of California".

[12] The regulated utilities still own hydro-electric and nuclear facilities.

[13] For example, see the California Energy Commission Publications 700-00-09, 700-00-10, 700-00-11, 700-00-12, from June through December 1999.

[14] Same as previous.

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[15] See California Energy Commission Publication 700-00-013 (Appendices E and F contain the actual forms).

[16] Same as previous.

[17] Where objectives from multiple sources (e.g., workstatement, OII) have been combined, the actual wording may vary somewhat from the original in order to accommodate both sources. However, the wording of objectives is consistent throughout this document.

[18] The origin of the objective is noted in square brackets.

[19] The environmental objectives will be designated as 1e, 2e and 3e to distinguish them from the interconnection objectives which are numbered 1, 2, 3...

[20] California Energy Commission Publication 700-00-005.

[21] Docket 99-DIST-GEN(2), Order Instituting Investigation "Exploring Revisions to Current Interconnection Rules Between Investor-Owned and Publicly-Owned Utility Distribution Companies and Distributed Generators", Order No. 99-1103-11, page 1.

[22] Large group meetings: 2/1/00, 2/2/00, 2/29/00, 3/7/00, 3/14/00, 3/21/00, 3/28/00, 7/11/00, 7/18/00, 7/27/00, 8/1/00, 8/15/00; Technical group meetings: 8/8/00, 8/9/00, 8/10/00, 8/16/00, 8/24/00; Hearings: 4/25/00, 6/29/00, 9/7/00; Advisory Committee meeting: 3/28/00.

[23] California Energy Commission Publication 700-00-014, Attachment A, "Full Text of Proposed Rule 21 Tariff Language"

[24] California Public Utilities Commission, Decision 00-12-037, December 21, 2000. Website address: http://www.cpuc.ca.gov/ PUBLISHED/FINAL_DECISION/4117.htm

[25] California Energy Commission, Publication 700-00-014, "Supplemental Recommendation Regarding Distributed Generation Interconnection Rules" October 2000, pages 14-17.

[26] Same as above, page 18.

[27] California Energy Commission, Publication 700-00-010, "Interconnection in California", June 1999. On the Commission website at.http://www.energy.ca.gov/reports/2000-10-17_700-00-010.PDF

[28] California Public Utilities Commission, Decision 00-12-037, December 21, 2000.

[29] P 1547 is the IEEE workgroup that is working toward a national interconnection standard.

[30] Mike Edds gave a presentation to the IEEE P1547 workgroup on the Initial Review Process he had developed in the California process. More recently, Chuck Whitaker, also of the FOCUS team, has been reporting to the IEEE on the Testing and Certification advances made in California.

[31] California Energy Commission Publication 700-00-014, Appendix A.

[32] Same as above, Appendix B.

[33] Type Tests for inverters include: Utility Disconnect Switch, Field Adjustable Trip-points, Field Adjustable Trip-points, Field Adjustable Trip-points, Field Adjustable Trip-points, Marking, DC Isolation, Simulated PV Array (Input Source) requirements, Dielectric Voltage Withstand Test, Power Factor, Harmonic Distortion, DC Injection, Utility Voltage and Frequency Variation Test, Reset Delay, Loss of Control circuit, Short Circuit Test, Load Transfer Test.

[34] Type Tests for synchronous generators include Utility Disconnect Switch, Field Adjustable Trip-points, Field Adjustable Trip-points, Field Adjustable Trip-points, Field Adjustable Trip-points – Marking, Dielectric Voltage Withstand Test, Power Factor, Harmonic Distortion, Utility Voltage and Frequency Variation Test, Reset Delay, Loss of Control circuit and Short Circuit Test.

[35] Type tests for induction generators include Utility Disconnect Switch, Field Adjustable Trip-points, Field Adjustable Trip-points, Field Adjustable Trip-points, Field Adjustable Trip-points - Marking, Dielectric Voltage Withstand Test, Power Factor, Harmonic Distortion, Utility Voltage and Frequency Variation Test, Reset Delay, Loss of Control circuit, Short Circuit Test and Load Transfer Test

[36] An IR is the initial statement of an interconnection requirement (IR). The comprehensive current statement of IRs is contained in the respective utilities' old Rule 21. The IRs are embedded in the document and sometimes technology dependent, sometimes not. These IRs had to be extracted from the old Rule 21. A PBIR (sometimes called a PBIR solution) is the consensus statement of the PBIR after discussion by the OII Technical Workgroup. The PBIRs are implicit in the Revised Rule 21 (see Attachment A); they are made explicit in this list. PBIRs are technology-independent in every case. This was not known when the Contractor began this project.

[37] California Energy Commission, Publication 700-00-010.

[38] California Energy Commission Siting Committee Recommendation on DG Interconnection Rules – May 2000, Attachment A, page 38. This is the "interim" version of the Revised Rule 21.

[39] See http://ulstandardsinfonet.ul.com/scopes/1741.html

[40] See http://standards.ieee.org/reading/ieee/std_public/description/staticp/519-1992_desc.html

[41] Same as previous reference.

[42] See http://www.nrel.gov/ncpv/hotline/utility_inter.pdf

[43] See Attachment A, "Revised Rule 21", Appendix A.

[44] California Public Utilities Commission, San Francisco, California, June 1, 1999.

[45] See Attachment A, Section 3.1.3.3

[46] See Glossary.

[47] The Energy Commission's website at www.energy.ca.gov/reports/2000-11-07_700-00-014.pdf.

[48] California Energy Commission Publication 700-00-006, "Final Energy Commission Recommendation Regarding Distributed Generation Interconnection Rules".

[49] California Energy Commission Publication 700-00-014, "Supplemental Recommendation Regarding Distributed Generation Interconnection Rules".

[50] The "Post-Implementation" Workgroup will hold its first meeting on February 1, 2001, as suggested in the "Forum for Addressing Future Changes to the Rule Once the Proposed Rule is Adopted", page 22, California Energy Commission Publication 700-00-006.

[51] The DG units covered in Section 3 is limited to those under 50MW in size. There is no such constraint in the Interconnection sections. The reason for the limitation here is to avoid covering the siting processes regulated by the Commission, which is the siting authority for all Generating Facilities at 50MW or above.

[52] This is emission certification, not to be confused with Interconnection Certification. To help maintain the distinction in this paper, the former meaning is in lower case, the latter is capitalized.

[53] California Energy Commission Publication 700-00-013. For the survey instruments, see Appendices E and F; for names of responding local jurisdictions see Appendix G.

[54] Same as above.

[55] Emission reduction credits (offsets) are applicable in non-attainment areas, those areas not attaining state or federal EPA ambient air quality standards.

[56] It should be noted that in the Bay Area Air Quality Management District certain projects eligible for accelerated permit processing can begin construction as soon as an application and fees have been submitted.

[57] These technologies do not require air permits in South Coast Air Quality Management District. Fuel cells, however, are not strictly "zero emissions" since some fuel cell technologies must burn natural gas until they get to temperature.

[58] See Section 2.2.5.2 for a listing of the 50 consensus PBIRs.

[59] Cost-critical policy issues are: 1.Cost of initial study; 2. Cost of supplemental study; 3. Ability to negotiate multiple sites with EC; 4. Time of initial study; 5 Time of supplemental study; 6. Rule uniformity; 7. EC (utility) discretion; 8.Agreement form; 9. Application form It is assumed that policy issues would weigh about twice as heavily as the PBIR solutions on a per-item basis, and that the workgroup, drawing on the work of Texas, could complete most of these on its own.

[60] Interconnection cost estimates are from California Energy Commission, Publication 700-00-09, "Market Assessment for Combined Heat and Power Systems in the State of California". Using these numbers as a baseline, the FOCUS-I workstatement estimates cost reductions based on

reduction in interconnection study fees, time to complete the interconnection study, and less onerous interconnection requirements. These estimates assume a 100 percent effective Rule 21. The assumption of progress at the end of FOCUS-I is a 50 percent effective Rule 21. The additional 50 percent of reduction is based on actual simplified interconnection through Certification, an electronic Application form and fully informed utility staff. This additional work is included in the effort called FOCUS-2.

[61] All currency totals are $ / kW.

[62] Expected gain is the difference between Scenario-1 and Scenario-3 as a percentage of the total cost of Scenario-1; Actual gain is the difference between Scenario-0 and Scenario-2 as a percentage of the total cost of Scenario-0.

[63] See endnote 7.

[64] This chart assumes year 2000 dollars and an average decline for all years. It uses no discounting.