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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Generation and Distributed Energy Resources.	FILED PUBLIC UTILITIES COMMISSION March 16, 2004 SAN FRANCISCO OFFICE RULEMAKING 04-03-017

ORDER INSTITUTING RULEMAKING REGARDING POLICIES, PROCEDURES AND INCENTIVES FOR DISTRIBUTED GENERATION AND DISTRIBUTED ENERGY RESOURCES

I. Summary

In this proceeding we continue our consideration of rules and policies impacting distributed generation (DG). DG has taken on greater significance in the energy industry since this Commission opened its last DG rulemaking in October of 1999 (R.99-10-025). The technologies of DG continue to evolve, and their potential benefits present a compelling set of options to be considered in the resource planning and procurement context. As expressed in state legislation, in the joint agency Energy Action Plan and the California Energy Commission's (CEC) recently adopted Integrated Energy Policy Report, evaluating and deploying DG is a priority for California's energy future[1]. There are multiple efforts underway to achieve these goals.

[1] Numerous pieces of enacted legislation have indicated the Legislature's intent to support DG, including but not limited to SB 1685 of 2003, AB 58 and SB 1038 of 2002, SB 82xx, SB 17xx, and SB 48xx of 2001, AB 918 and AB 970 of 2000, and others. California's first Net Metering law, described below, was enacted in 1995 via SB 656.

Footnote continued on next page

This Commission has made a substantial effort to stimulate DG installations by providing multiple technologies with financial incentives and exemptions from standby rates and DWR cost responsibility surcharges. The CEC, through its ratepayer-funded Public Interest Energy Research (PIER) program, has spent more than $80 million to study and support DG in recent years. In this Rulemaking the Commission will ensure that California's investor-owned utility customers get the maximum possible benefit from these policies.

It is equally true, however, that there is much left to learn regarding the true costs and benefits of adding DG to the electrical system; about the proper levels of public subsidies or incentives for various DG technologies; and about the extent to which DG can and should be incorporated into IOU long-term resource planning and procurement. This Rulemaking will update the record of our predecessor DG rulemakings, taking a broad look at the reality and potential of DG, and will allow the Commission to make informed decisions from a base of facts that we will strive to keep current. We will scope this Rulemaking to answer the challenging technical questions regarding DG posed by the Legislature, the utilities, and DG developers.

Work in this Rulemaking will be divided into five tasks:

1. The first is to develop the cost-benefit analysis methodologies for DER and for net metering as called for by the Legislature.[2]

The CEC's Integrated Energy Policy Report is publication number 100-03-019F, November 2003 and can be found at http://www.energy.ca.gov/energypolicy/index.html

[2] Pub.Util.Code Sections 353.9 and 2827(n)

2. The second is to carry out our responsibility to administer the Self Generation Incentive Program mandated by AB 970 and modified by AB 1685, and to optimize the coordination of our incentive program with that of the CEC.[3]
3. Third, we will develop further guidance for the IOUs on the use of DG as a planning and procurement resource, in keeping with the direction on long-term planning contained in D.02-10-062, the "Regulatory Framework" decision returning the IOUs to the business of procurement. It is in this area that we will consider any necessary changes to the state's Net Metering program for DG. This direction was updated in D.04-01-50 with specific instructions to the utilities in preparing their long-term plans, as described below.
4. Fourth, we will examine to the extent necessary the outstanding technical issues arising from the Commission-authorized tariff Rule 21 interconnection process managed by the CEC (see Appendix A for a report provided by the CEC, containing input on these outstanding issues from the Rule 21 Working Group).
5. Finally, we hope to explore associated, emerging technologies of Distributed Energy Resources (DER), (defined below, and of which DG is a subset), such as hydrogen fuel cells, microgrids, and electrical storage, among others, in order to bring the benefits of ratepayer-funded research and development into the IOU resource mix. The first three tasks are the top priorities of this rulemaking; we will address the last two topics as issues dictate and the schedule permits.

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[3] December 30, 2003 ALJ Ruling (R.98-07-037)

II. A New Comprehensive Framework – Distributed Energy Resources

Distributed generation encompasses many technologies and is subject to a seemingly equal number of definitions. We will offer our own below, subject to update as our understanding develops in this Rulemaking. Part of this confusion about definitions results from the existence of a range of technologies and resource options that share similar characteristics on or near the demand- or customer-side of the meter, such as the ability to serve or otherwise mitigate load without the sustained, direct involvement of the utility.

In addressing what we consider to be the three central issues in this rulemaking – cost-benefit analyses, incentives and IOU procurement guidance – we intend to develop a conceptual framework that will allow us to evaluate these similar resource options on an equal footing. With this Rulemaking we will begin to employ the name Distributed Energy Resources (DER) to encompass distributed generation, energy efficiency, demand response and electrical storage. These resource options share common characteristics in their ability to serve or otherwise manage onsite load, and in the potential benefits they can provide to the electrical network if employed with sufficient care and foresight.

We will not elide the important differences among these resource options, but in developing a formalized understanding of their similarities and differences we will enhance our ability to judge all options on an equal basis. A ratepayer dollar invested in one of these technologies will indicate that a careful balancing of options has taken place, and that the IOU has employed a Commission-approved methodology reflecting substantial party input. In the long run this approach will benefit ratepayers and the entities that serve them.

In future iterations of our proceedings addressing efficiency, demand response, and electrical storage (when and if storage technologies become a cost-effective resource option[4]), we will introduce the concept of DER and seek to develop and employ a uniform cost-benefit test in judging the suitability of these options for utility planning and procurement. This standard framework will in turn influence our consideration of incentives for utilities and their customers.

This standardized cost-benefit test ultimately involves the calculation of avoided costs over some time frame, typically the short run (SRAC) or the long run (LRAC). This exercise is currently underway in a number of forums before the Commission: in the energy efficiency proceeding, in the implementation of the Renewable Portfolio Standard, in the treatment of QF resources (as discussed in D.04-01-050), in our previous distributed generation proceeding, and now here.

These efforts are essentially technology-specific attempts to answer a common question: what is the value of deferring an IOU investment in traditional generation resources? The answer to this question is the foundation of the benefits side of the cost-benefit analysis, to which consideration of externality avoidance and other technology-specific attributes should be added.

The Commission intends to develop a common methodology for assessing avoided costs across the full range of supply- and demand-side technologies, to be employed as a fundamental component of integrated IOU planning for the short and long term. We intend to undertake this effort in 2005, which is an "off year" in the two-year planning cycle we have implemented for the IOUs.

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[4] Energy storage does not presently have a place in a Commission proceeding, and given the relatively experimental nature of such technologies is not likely to warrant a proceeding of its own. Unless or until it does, we will utilize this proceeding to increase our understanding of storage technology options.

While this integrated approach to avoided cost is our near-term goal, however, we see no reason to delay the development of avoided cost methodologies in the specific proceedings and program areas to which they can be immediately applied. These proceedings, including this one, should move forward in developing appropriate avoided cost methodologies, and establish robust records that will be of use to the Commission when the effort of integrating these methodologies into a common framework commences later this year.

To that end, this proceeding will focus on developing a cost-benefit methodology for DG, in accordance with our direction from the Legislature. For this DG rulemaking we propose to adopt a modified version of the CEC's definition of distributed generation.

> Distributed Generation (DG) is a parallel or stand-alone electric generation unit generally located within the electric distribution system at or near the point of consumption.[5]

DG definitions also vary with respect to the maximum allowable size of the generating unit. The industry broadly characterizes units that are 20 MW or smaller (and otherwise consistent with the definition above) as DG, in part because 20 MW is the maximum capacity size that most utility distribution systems can accommodate. Using this definition, according to the CEC approximately 1980 MW of DG units were installed in the service territories of PG&E, SCE and SDG&E as of December 2003. We will need to develop a definition of what "at or near" means in this context. Further, we are aware that

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[5] The CEC calls these generation units Distributed Energy Resources. Since we are using DER to encompass a broader range of resource options, we will continue to refer to the generation subset under consideration in this rulemaking as Distributed Generation.

the above definition would potentially encompass larger generation units and Qualifying Facilities, and may therefore be too broad.

For now, however, we will not adopt the distinction of 20 MW or less, pending a demonstration of why this number and not some other is the critical threshold. DG technologies are changing quickly, and ongoing research may allow for deployment of larger capacity DG units in ways that benefit the grid or onsite power consumption. We will look for guidance in the pending record on the proper upper limit, if one exists, for classification as DG. Ultimately we must develop a standard definition of DG in order to harmonize the multiple objectives of ongoing DG programs and recent DG legislation.

III. Background - Recent DG Findings and Outstanding Issues

The prior DG rulemaking (R.99-10-025) principally examined the potential of DG to benefit the distribution system. In the timeframe of our previous rulemaking, when this Commission was not engaged in significant resource planning, such a limited focus was sensible. Now, however, to truly answer outstanding questions of costs and benefits, tariff structure and interconnection, and subsidy and market transformation, we step back to broaden our scope of inquiry. We expect that the record we develop here will reflect the increased understanding and market experience of DG resources, and as such we may revisit issues addressed in previous Commission decisions, as appropriate.

In May 2003, the Commission, CEC and California Power Authority (CPA) adopted an Energy Action Plan establishing objectives for the state's energy future. A number of issues concerning DG are identified in the plan. Specifically, as expressed in the EAP, the state will:

1. Promote clean, small generation resources located at load centers;

2. Determine whether and how to hold distributed generation customers responsible for costs associated with Department of Water Resources power purchases;
3. Determine system benefits of distributed generation and related costs;
4. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program;
5. Standardize definitions of eligible distributed generation technologies across agencies to better leverage programs and activities that encourage distributed generation;
6. Collaborate with the Air Resources Board, Cal-EPA and representatives of local air quality districts to achieve better integration of energy and air quality policies and regulations affecting distributed generation;
7. Work together to further develop distributed generation policies, target research and development, track the market adoption of distributed generation technologies, identify cumulative energy system impacts and examine issues associated with new technologies and their use.

We solicit comments on achieving these goals, with the exception of DWR cost responsibility (accomplished in D.03-04-030, and not to be re-litigated here) and RPS participation (ongoing in the RPS phase of R.01-10-024). DG as an energy resource for the IOU and ratepayer needs now to be considered in a broader policy context, building on the work completed in the Commission's previous DG proceedings, and connected to the resource planning and procurement process with specific findings and directives.

IV. DG Issues before the Commission, CEC, Power Authority and Air Resources Board

With the direction provided in the Regulatory Framework decision of last year D.02-10-062 the Commission expanded the role of DG as a utility procurement option, directing the utilities to include DG in utility long-term generation and distribution planning. In the most recent Procurement decision, D.04-01-050, the Commission found that the IOU's long-term plans did not contain sufficient detail regarding how this direction is being implemented. In the next round of long-term plan filings each IOU is to provide the following: a line item entry identifying distributed generation separate and apart from other entries such as energy efficiency and demand response; the energy (GWh) and demand (MW) reduction attributed to distributed generation; and a description of the technologies the utility includes in its definition of distributed generation, as well as a statement noting whether its forecast includes utility-side distributed generation, such as QFs.

The Self Generation Incentive Program (SGIP) will be incorporated into this rulemaking. The Commission will address the continuation of program funding through 2007, as well as the additional eligibility requirements adopted in AB 1685. We intend to complete our mid-program evaluation, consider recommendations for program improvements as allowed within the framework of AB 1685, and identify opportunities for further action by the Legislature.

The number of solar, wind, and biogas net metering installations have increased since 2001, largely due to the availability of incentives and the expansion of California's net metering program to include systems with higher generating capacity. In recognition, the Legislature directed the Commission to study the environmental impacts of net metering. In conjunction with this assessment, this proceeding may also identify necessary changes to state and federal statutes that will enable California's net metering program to achieve its highest potential.

The CEC undertakes a number of important DG-related activities, including the Commission-approved facilitation of the state's DG interconnection working group process (see Appendix A)[6]. In addition, the CEC administers the renewable DG subsidy funds under the Emerging Renewables Program, and supplies ratepayer funds to DG research and development projects through the PIER program. Finally, the CEC manages the bid process to determine customer exemptions from cost responsibility surcharges (CRS), pursuant to criteria established in Commission D.03-04-030. We plan to continue our collaboration with the CEC, including coordination between our SGIP and the Emerging Renewables Program, bringing the results of PIER R&D into the planning and procurement process, and any necessary reforms to the Rule 21 program.

The CPA is presently engaged in a Request for Bids in its State Facility Solar Energy Sales Program, to enable state agencies to meet their goal of implementing all cost-effective solar PV projects, as mandated by SBxx 82 (2001). This effort falls within the scope of the CPA's 2003-2004 Energy Resource Investment Plan and its emphasis on efficiency and DG in public facilities across the state. Other CPA projects in the DG area will be considered in this proceeding as appropriate.

As of January 1, 2003 the Air Resources Board (ARB) is responsible for ensuring that DG technologies that are exempt from air pollution control or air quality management district permits meet specific emission standards and other requirements before they can be sold in California. The ARB has also developed guidance for districts in making permitting decisions for DG technologies that require such local certification. By July 2005 ARB staff must complete a

[6] The CEC adopted its Distributed Generation Strategic Plan on June 12, 2002, which we plan to take official notice of in this proceeding.

technology review for the Board to evaluate whether the emissions standards established in ARB regulations should be modified. Additionally, we are required to incorporate the AB 1685 emissions and efficiency SGIP eligibility requirements by January 2005. We will coordinate our SGIP rules with these new regulations. The Commission is committed to promoting clean DG and to monitoring the emissions of the state's DG facilities, and will assist the ARB in its responsibilities via this proceeding.

V. DG Issues before the Federal Energy Regulatory Commission

On July 24th, 2003 FERC issued a Notice of Proposed Rulemaking (Docket No. RM02-12-000) on "Standardization of Small Generator Interconnection Agreements and Procedures," the results of which will bear directly on the work undertaken in this proceeding. The proposed NOPR approach to these issues appears to be compatible with what California has implemented in its Commission-authorized tariff Rule 21 interconnection process, and in fact closely resembles the model rule developed and filed at FERC by California, Texas, Ohio and New York, under the auspices of the National Association of Regulatory Utility Commissioners. To the extent that this proves true, we will encourage FERC to pursue its NOPR as it is presently established.

We hope, through the input of parties in this proceeding, to develop a solid foundation for arguments at FERC that will protect California's ratepayers, utilities and DG customers, and allow us to implement DG policies that best reflect California's needs and the public interest. We will develop a California position on these issues, with input from our colleagues at the CEC and the California Independent System Operator (CAISO).

FERC's influence on DG policy in California also potentially extends into the realm of net metering, and the ill-defined border between a net-metered and a wholesale transaction. While it does provide a bill credit for the sale of excess power to the grid, at present the net metering system in California does not allow for payments from the IOU to the DG owner. Hence there has been no need for a FERC-approved wholesale tariff governing such transactions. In order to maximize the benefits of DG to the California system, however, we may wish to consider developing such a tariff for submission at FERC, one that will promote the types of DG technologies and transactional relationships that California favors. We invite parties to comment, and to assist us in taking a leadership role on this issue as we act on our statutory authority to represent California at FERC.

VI. DG Issues Impacting the CAISO

On June 12, 2002 FERC approved the CAISO's Aggregated Distributed Generation Pilot Project (ADGPP). The Project was "designed to test arrangements for Generating Units with a rated capacity less than 1 MW that are not currently accommodated in CAISO markets to be aggregated into blocks no less than 1 MW but less than 10 MW, and to, in an aggregated fashion, schedule Energy with the CAISO and participate in the CAISO's Supplemental Energy Market."[7] Due to a number of uncertainties, program design and other mitigating factors, such as the possible imposition of exit fees on DG customers and the necessity of complying with the ISO's ramp rates, the Project was terminated on December 31, 2002 with no active participants.

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[7] "Report of the California Independent System Operator Corporation," January 30, 2003, filed in FERC docket ER02-1651-000.

Despite this lack of participation, the CAISO has expressed its interest in further pursuing such an aggregation of DG units for participation in the Supplemental Energy Market or other CAISO program. Like the development of a wholesale tariff for DG transactions, such an initiative may prove necessary to maximize the potential of DG in California.

We invite parties to comment here, as well as in relevant proceedings at the CAISO, on how to effectuate such an aggregation program. It may be the case that such an effort is best undertaken by the CAISO; if so, parties should make this argument, and describe any coordinating or supplementary efforts this Commission should undertake towards this end. CAISO has also expressed its concern that, as DG policy is further refined, we ensure that DG is assessed a fair allocation of system costs and that sufficient reserves are procured to cover firm load served by DG. We share these concerns, as expressed elsewhere in this document, and will collaborate with the CAISO on these and other issues in the course of this proceeding. We also note that reserve issues are presently being considered in the Procurement docket, and we will coordinate with that docket on this point.

VII. Recent Commission Decisions Impacting DG

As noted above, the Commission held in D.04-01-050, the “Long-Term Plan” decision, that further detail was required in the IOU long-term plans regarding the treatment of DG. In their next long-term plan filings, the IOUs are to provide the following: a line item entry identifying distributed generation separate and apart from other entries such as energy efficiency and demand response; the energy (GWh) and demand (MW) reduction attributed to distributed generation; and a description of the technologies the utility includes in its definition of distributed generation as well as a statement noting whether its forecast includes utility-side distributed generation, such as QFs. Consideration of parties' proposal for a set-aside for DG was also referred to this new proceeding; parties are invited to re-submit this proposal here.

In order to fulfill on an interim basis the requirements of Pub.Util. Code § 353.13(a), the Commission in D.03-04-060, the "Standby Charge Exemption" decision, extended a legislatively-enacted waiver of standby charges for the following two DG categories sized 5 MW or smaller: renewable and combined heat and power DG[8], installed between May 2001 and December 31, 2004, and ultra-clean DG[9] units, installed between January 1, 2003 and December 31, 2005. This extension allows the DG market to continue to grow while the Commission implements appropriate standby rates in the IOUs' general rate cases.

In establishing the applicability of Cost Responsibility Surcharges (CRS) to DG, the Commission in D.03-04-030, the "Cost Responsibility" decision, rejected a proposed Settlement Agreement, finding that it was

> "inconsistent with Legislative direction contained in several bills…which indicated a policy preference for customer generation in general, as well as clean Customer Generation in particular. Further, we believe giving customers preferential access to ultra-clean and low-emission generation serves the public interest in general, and not just the particular interests of the individuals who choose to install customer generation" (D.03-04-030 at p.42).

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[8] As defined in D.02-10-062.

[9] As defined in Pub.Util.Code 353.2(b).

Presently, all technologies 1 MW or less and eligible for SGIP funding are also eligible for CRS exemption. Assembly Bill 1685 establishes new efficiency and emissions eligibility requirements combustion technologies must meet in order to receive incentives. When evaluating SGIP eligibility we will be careful to consider the implications for CRS exemption, and to guard against any unjustified CRS cost-shifting that may result if SGIP eligibility expands to include other technologies.

In D.03-02-068, the "DG Integration" decision, the Commission reached a number of conclusions regarding the potential of DG to benefit the distribution system, and gave some direction regarding issues to be taken up in this new Rulemaking.

The decision found that DG can serve to forestall distribution system upgrades, and should be valued as such, but found these benefits to be limited in time, as load continues to grow and distribution upgrades become unavoidable. The Commission directed the IOUs to incorporate DG into grid-side system planning and procurement in the following way:

- The IOUs will establish performance criteria to determine when a DG installation can function as an alternative to new distribution;
- The DG community will be made aware of these criteria, and contacted in advance regarding specific locations where the IOU is considering a DG installation;
- Once the IOU determines that a DG solution is viable, procurement of DG will commence, with the selection process following a documented and defensible decision path;
- The grid-side DG solution can be owned by the IOU or provided by a third party, although we discourage IOUs from owning on a long-term basis DG systems that forestall distribution upgrades, and direct the IOUs to evaluate these

temporary installations in their long-term planning and procurement processes;

- In cases of IOU ownership, the value of the distribution deferral should be credited to the utility from the distribution budget, while payment to third-party grid-side DG owners should be no greater than the amount calculated for the deferral of a planned distribution addition;
- Physical assurance in the form of control and dispatch of the grid-side DG unit by the IOU is required in all cases.

The utilities provided implementation proposals to the Energy Division in September 2003. We direct the utilities to update these proposals as necessary, and to file the proposals in this docket within two weeks of the issuance of this order.

Regarding customer-side DG installations, D.03-02-068 reached the following conclusions:

- Customer-side DG has the potential to meet peak demand in areas experiencing load growth;
- IOU ownership of customer-side DG is neither prohibited nor encouraged;
- IOU-owned customer-side DG should be treated as a generation asset, with revenues offsetting IOU costs of operation;
- Outstanding issues such as they exist regarding standby charges, interconnection processes, and net metering should be taken up in this new Rulemaking.

The decision found that the Commission should consider a valuation system for the environmental benefits of renewable DG in designing future procurement policies. DG can serve peak load and provide resulting system-level benefits, and while a valuation of these benefits is unnecessary, consideration of them should be incorporated into IOU long-term planning and procurement. The decision found that the extent to which these benefits should offset departing load charges assessed to installers of DG systems should be considered in this new DG Rulemaking.

We intend to examine in this proceeding any outstanding issues identified in D.03-02-068 regarding standby charges, interconnection processes and net metering, and to emphasize the general task of establishing a cost-benefit test to address the concerns raised in that decision. We do not intend to revisit CRS exemption here, however, as the issue was resolved subsequent to this Decision in D.03-04-030, with one exception as stipulated above: when considering the addition of new DG categories to the SGIP program, we will carefully evaluate the impact of shifting the CRS burden to IOU ratepayers.

In giving direction to the utilities on issues to consider when developing their long-term resource plans, the Commission in D.02-10-062, the “Regulatory Framework” decision, expressed a preference that DG be given serious consideration, finding that “the utilities should explicitly include provision for distributed generation and self-generation resources in the procurement plans…In addition to providing capacity and energy benefits, (DG resources) can offer transmission and grid-support benefits that should be included in the utilities’ procurement plans.” (Decision at p.27)

In response to AB 970, in D.01-03-073, the “Load Control and DG Initiatives” decision, the Commission established the Self-Generation Incentive Program. D. 01-03-073 provides up to $125 million in annual incentives for certain DG technologies through 2004, differentiating by DG technologies to give preference to cleaner forms of generation. AB1685 (Statutes of 2003) extends the program through the end of 2007 and calls for more specific program modifications. Given that the program was originally set to expire at the end of

2004, we will need to, in this proceeding, evaluate changes that should be made in a Commission decision before the end of 2004.

Lastly, the Interconnection Standards (Commission-authorized tariff Rule 21) adopted in D.00-11-012 and D.00-12-037 (the “Rule 21” decision) “pre-certify, standardize and track the performance of distributed generation, which…may make (DG) an increasingly attractive option to enhance reliability on the distribution system.” This proceeding should attempt to learn from the data that has been collected so far in this process, and assess whether further study or changes to the Commission-authorized tariff Rule 21 interconnection process are warranted. Appendix A contains a report from the CEC on Commission-authorized tariff Rule 21 issues, and we will continue to rely extensively on the expertise of the CEC in this area of DG policy.

VIII. Agency Collaboration Expected in this Proceeding

Consistent with the goals of the Energy Action Plan, this Commission appreciates and reaffirms its close working relationship with the CEC on DG issues, extending a collaboration that began five years ago with R.98-12-015 and continued with R.99-10-025 and R.98-07-073. The CEC will not be considered a formal party to this proceeding; instead we will establish a close staff-level collaboration on the full range of DG issues. For instance, we will examine the CEC’s R&D efforts in the area of DG for guidance in the development of our cost-benefit analyses. We continue our collaboration with the CEC renewables program to ensure consistency between statewide incentive programs. We also endorse the CEC’s continued oversight of Rule 21 interconnection activities and look to the CEC and the Rule 21 Working Group for policy guidance in the area of interconnection issues.

We also invite the participation on a collaborative, non-party basis of the CPA and the state Air Resources Board and California Environmental Protection Agency, as these latter two agencies seek to understand the environmental impacts of the various DG technologies being deployed in the state.

Lastly, we note that the participation of renewable DG technologies in the state's new Renewable Portfolio Standard (RPS) program is under consideration in the RPS phase of the Procurement proceeding. We will coordinate with that proceeding as well, and lend support from this record to the state's ambitious goal of achieving a generation portfolio that is at least 20% renewable.

As a general principle we hope to streamline the process of data collection and analysis by all agencies involved in state DG policy, and make this information available to the public to the fullest extent possible.

IX. Preliminary Scoping Memo: Scope of the Proceeding

This new Rulemaking divides the present task into five issue areas:

Cost-Benefit Analyses for Customer and IOU Installations: As noted above, this is the highest-priority task for this proceeding, both in meeting our legislative obligations and in developing the conceptual underpinnings for our new approach to Distributed Energy Resources. Issues of particular interest include the definition of Distributed Generation, positive and negative impacts of DG exporting power to the grid, whether deliberately or inadvertently, environmental and economic impacts of net metering, and the degree to which DG additions that affect utility reserve requirements are reflected in project economics.

The value of a potential DG installation depends on the viewer's perspective: for instance that of the IOU, the developer, the ratepayer, or the owner/installer. At times these multiple interests will intersect, and in these cases the state's goals for DG expansion should be most vigorously pursued[10]. At other times the IOU's interest in customer stability may conflict with the desire of a potential DG installer for premium power. In all instances we must guard against unjustified cost-shifting that may result from broad DG deployment, within and across customer classes. We will be in a better position to evaluate these and other issues with the analytic tools and planning guidelines to be developed in this proceeding, beginning with the cost-benefit analysis called for by the Legislature.

To that end we must decide whether to develop a cost-benefit analysis methodology that is rigorously quantitative, deriving explicit dollar values for every aspect of a DG project, or rely instead on a qualitative method, judging project characteristics against a list of attributes ranked by desirability. We note that the responsibility on the part of this Commission to develop a cost-benefit test originates in Pub.Util.Code Section 353.9, enacted in SB 28x of 2001, as follows:

> "The commission shall create a firewall that segregates distribution cost recovery so that any net costs, taking into account the actual costs and benefits of distributed energy resources, proportional to each customer class, as determined by the commission, resulting from the tariff modifications

[10]Some contend that a more extensive reliance on DG would have mitigated the impacts of the August 14th, 2003 East Coast blackout. We invite parties to comment on the validity of these claims, the extent to which this potential role for DG should influence IOU resource planning and procurement, and the manner in which this consideration should be reflected in the cost-benefit test we will develop in this Rulemaking.

> granted to members of each customer class may be recovered only from that class."[11]
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> Similarly, Pub. Utilities Code Section 2827(n) Public Utilities Code § 2827(n) directs the Commission to "assess the environmental costs and benefits of net metering to customer-generators, ratepayers, and utilities, including any beneficial and adverse effects on public benefit programs and special purpose surcharges."

A qualitative cost-benefit test would be appropriate were the question merely whether to approve or deny a DG proposal. A general determination, for example, that a DG facility postpones the need for a costly distribution system upgrade, and will result in a negligible increase in emissions, would allow the Commission to approve a DG project as in the ratepayer's interest and satisfactory from the cost-benefit standpoint. This, however, is not the test proposed by the Legislature; *actual costs and benefits* are to be determined, netted and tracked to guard against cost-shifting, and to accomplish this the Commission must develop dollar values for each characteristic of a DG project. We ask for party input on the characteristics that must be monetized in this way, such as the deferral of distribution upgrades, the provision of voltage support or peak-shaving energy, changes to the emissions profile of the state's generating stock, and any other relevant issues.

An important contribution to this effort may come from the avoided cost study mandated by AB 970, presently under consideration in the Commission's energy efficiency docket (R.01-08-028). This study, the product of multiple

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[11] The meaning of distributed energy resources in this context is synonymous with our present use of DG, not the larger set of resource options including efficiency, demand response and storage.

Commission workshops and ongoing stakeholder processes, will establish avoided cost estimates attributable to efficiency investments in the areas of: transmission & distribution investments forestalled; reduction in the cost of on-peak energy; avoidance of environmental damage associated with electricity generation; and grid reliability improvements. A number of these characteristics may also be applicable to DG on the benefit side of the cost-benefit ledger.

When the report and its underlying methodologies are complete they will be presented for consideration by the Commission, and, assuming they are formally adopted and available in a timely manner, will be incorporated into this new Rulemaking as a reference document. Parties will have an opportunity to consider the applicability of these avoided cost methodologies, and any necessary changes to them, to our present task of cost-benefit analysis for DG projects. Alternatively, should this methodology prove inappropriate to DG, we will develop the necessary methodologies independently of those established in our efficiency proceeding, utilizing all the resources available to the Commission, including the ongoing work in the PIER program.

We also note that the Legislature expresses its concern over cost-shifting in terms of customer classes – DG installations shall not burden customers in *another* class. We are equally concerned, however, that DG customers not unjustifiably shift costs to those within their class that remain under IOU service. Parties are asked to comment on whether the Commission should establish a new customer class entirely comprised of DG customers, and to contain all DG-related costs within that class, or whether the Commission should consider some other method of ensuring that costs are appropriately shared as DG usage expands.

Finally, to enable fully informed resource planning and procurement decisions based on complete cost and benefit information, we hope to develop a comprehensive record comparing the emissions profiles of DG technologies to those of modern central-station facilities.

We anticipate that the cost-benefit analysis issue will occupy the majority of this new Rulemaking's effort in its early phases, and invite comments on the full range of implicated issues, not simply those raised here.

DG as a Utility Procurement Resource: In Decision 02-12-071 this Commission directed the utilities to consider DG as a resource in their long-term planning and procurement processes. This new DG rulemaking can assist in this area by expanding our understanding, via the cost-benefit test, of the positive and negative effects of DG installation on the IOU side of the meter, of DG's potential contribution to utility reserve requirements, and of the role of DG in ensuring overall resource adequacy. To the extent that technological advancement has improved the ability of DG to forestall distribution upgrades, we will reconsider the question here, incorporating the ongoing research on DG grid effects being conducted by the CEC's PIER program. It is in this area of the proceeding that we will consider any necessary changes to the state's Net Metering program for DG.

In this subject area we will also examine the manner in which direction provided in D.03-02-068, the Energy Action Plan, and legislation can best be employed in the planning and procurement process of the IOUs. As noted above, we call upon the IOUs to provide an update on the implementation of D.03-02-068 within two weeks of the issuance of this order, and reiterate the finding in D.04-01-050 that more detail is required in the IOU long-term plans regarding the role of DG.

Some contend that a more extensive reliance on DG would have mitigated the impacts of the August 14th East Coast blackout. We invite parties to comment on the validity of these claims, the extent to which this potential role for DG should influence IOU resource planning and procurement, and the manner in which this consideration should be reflected in the cost-benefit test we will develop in this Rulemaking. Information developed in this area of the Rulemaking will be made available for use by the Commission and parties in R.01-10-024, the General Rate Cases, and with R.03-03-015, which is currently investigating whether added rates of return should be afforded to certain types of DG, for use in long-term planning, procurement and evaluation.

Future Incentives for Customer-Side DG: The third priority issue is the question of public subsidies for DG development. California presently provides incentives to encourage the installation of customer-side DG through programs administered by this Commission and by the CEC. This Commission's program, the Self-Generation Incentive Program (SGIP), is open to larger-scale DG systems, and has the goal of reducing peak system demand. The Emerging Technologies Account in the CEC's Renewable Energy Program supports smaller DG systems, with the goal of market transformation to promote these technologies' eventual cost-competitiveness. The Commission is presently evaluating the SGIP, including how to implement AB 1685, in the efficiency, low-income assistance, and renewable R&D docket (R.98-07-037). In establishing this rulemaking we will consolidate SGIP issues for consideration here, closing docket R.98-07-037, and coordinate their resolution with the CEC's ongoing program evaluation and our own Procurement rulemaking.

We are interested in exploring improvements to the SGIP. An ALJ Ruling issued December 10, 2003 requested comments on program evaluation reports prepared and submitted by Itron Consulting Group.[12] The ruling also solicited proposals regarding AB 1685 implementation.[13] Recommendations included a flat "dollar per watt" incentive structure without percentage caps, sequenced incentive reductions per unit of installed capacity as funds are depleted, and an exit strategy linking incentive levels to what we anticipate would be declining market prices as DG technologies mature.

We must also ensure that our eligibility requirements reflect the emissions standards under development at the ARB, to be implemented in 2007. Consideration will be paid to the encouraging or discouraging of the use of natural gas as a fuel for DG facilities. It may also be beneficial to examine the interplay of the two stated goals of the Commission and CEC programs, the extent to which they reinforce each other, and whether any redundancies or inconsistencies can be removed to make the subsidy efforts more targeted and efficient. Parties are asked to comment on the full range of these issues.

Outstanding Interconnection and Related Technical Issues: Many issues have been successfully addressed in the Commission-authorized tariff Rule 21 Interconnection Working Group process. Our colleagues at the CEC, as detailed in Appendix A, inform us that a number of issues regarding standby charges, interconnection processes and net metering remain unaddressed. Some of these issues necessarily appear in the other categories scoped here, but we raise them in the Rule 21 context to determine which, if any, need to be specifically

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[12] Formerly known as Regional Economic Research Consulting Group (RER)

[13] December 10 ALJ Ruling Requesting Comments on AB 970 Self Generation Incentive Program Evaluation Reports and Related Issues is available on the Commission website www.cpuc.ca.gov/word_pdf/RULINGS/32412.doc

addressed as Rule 21 issues. Answers to these questions will be important to other aspects of this proceeding, in particular the cost-benefit analysis, and will influence the guidance this rulemaking provides to other proceedings, including Procurement. As noted above, we hope to hear from parties regarding the recent FERC NOPR on small generation interconnection and the extent to which it is compatible with California's CPUC authorized tariff Rule 21 procedures. We are particularly interested in hearing from parties regarding the present system of dispute resolution and suggestions for any necessary improvements.

DG Issues for the Future: DG technologies and the industries that support them are evolving and offer a range of possibilities for the energy future, as well as a potential source of economic development for the state. The CEC's programmatic emphasis on market transformation, and the DG work undertaken as part of its PIER program – upwards of $80 million in ratepayer funds to date - should be more directly incorporated into this Commission's resource planning and procurement process to take advantage of this potential. In this area of the Rulemaking the Commission will expand its understanding of the potential for advanced DG systems in areas such as fuel cells, hydrogen production, microgrids, storage, and modular systems that provide energy for stationary and mobile uses.

Our ongoing collaboration with the CEC will help us to understand and incorporate these technologies when and if they become viable, and we invite the participation of groups such as the California Fuel Cell Collaborative to contribute to our understanding of these emerging technologies. We hope to elicit the participation of local governments in resource-constrained areas where DG technologies, both established and experimental, may help to meet load. Evaluation of the potential for DG aggregation will also be undertaken in this subject area. Many advanced DG technologies are speculative at present, but we have reason to believe that the participation of the investor-owned utilities will be crucial in any eventual success that may result. The transition to a sustainable energy future may require an impetus from the regulatory process, before market forces can effectively engage disruptive technologies and deliver on their substantial promise.

X. Summary of Issues to be Considered in this Proceeding

To summarize, following is an initial list of the issues to be considered in this proceeding, and questions we ask parties to respond to as we prepare to scope this new Rulemaking.

1. General issues

The Commission, the CEC, the CARB, and the utilities are required to collect a significant amount of DG data in connection with administering incentive and net metering programs, and through legislatively-mandated data collection programs.

- How could these entities share data and streamline data collection?
- How could performance data collected from DG customers be verified?
- How could DG data be formatted to be made publicly available?
- Please identify all known DG data collection mandates and data sources.
- Parties should comment on the implementation of DG-related goals stipulated in the joint agency Energy Action Plan, as described above.
- How should the Commission coordinate its DG-related activities with those of the CPA, if appropriate?

2. Cost-Benefit Analysis for Customer and IOU Installations

- What is the proper definition of DG, including MW size ranges, for standardization across state agencies and programs?
- How might DG development affect the relative liabilities of ratepayers, utilities, DG owners and others?
- How are the avoided cost (and cost components) being developed in R.01-08-028 relevant to this inquiry? What changes are necessary for them to be applicable to the cost-benefit analysis of DG and net metered projects?
- Should a separate market structure (retail market or exchange) be created for the full range of DG technologies? Could this market be structured to maximize or aggregate the benefits at reasonable costs? How could consumer protections be established for any potential market structure?
- What are the positive and negative aspects of DG additions that need to be monetized?
- Which specific approaches to DG and net metering cost-benefit analyses should be adopted, and how should these analyses be employed by the Commission and the IOUs?
- Are standby charges and reserve requirements properly assessed and applied to DG projects?
- What are the emissions characteristics of present DG technologies, and in light of the pending ARB regulations, how should the Commission expect these characteristics to change over time?
- How should the Commission interpret the language of Pub.Util.Code 353.9, which requires that net costs of DG systems be recovered only within the DG owner's customer class? Should the Commission establish a separate customer class, or separate customer classes, to encompass DG installations, and contain net costs and benefits within each class?

3. DG as a Utility Procurement Resource

- We direct the IOUs to provide an update on the implementation plan to incorporate DG into grid-side system planning, as stipulated in

Ordering Paragraph Two of D.03-02-068, to be submitted within two weeks of the issuance of this Order.

- Are there initial results from the DG Integration decision, D.03-02-068, which should be considered, and integrated with the resource planning and procurement process underway in R.01-10-024? What other dockets should this proceeding be coordinated with?
- Should the Commission consider any changes to the Net Metering program at this time?
- What is the potential for DG to mitigate the effects of blackouts, as some have contended in response to the August 14th, 2003 East Coast blackout?
- Generally, what role should DG play in the resource adequacy and reserve requirement equation of the IOUs?
- Are there tariffs or rates that could be crafted to provide better retail price transparency to DG? Could participation costs be reduced? Could the full range of DG participate?
- Can market rules and regulations be modified to allow DG to participate in current wholesale markets? Will they be consistent and stable? Can transaction and participation costs be reduced for DG? Could the full range of DG participate?
- How can utility distribution planning practices be modified to enable DG to provide distribution deferral and be compensated for it?
- Should distribution design be modified to be more accommodating to DG?
- What steps should the Commission take, if any, to influence the use of natural gas in DG systems?

4. Net Metering

- Is the current net metering capacity allowance of .5 percent of an electric service provider's aggregate peak demand sufficient to accommodate for increased net metering installations in all IOU service territories?
- Should the Commission consider reforms to the net metering program, such as development of a wholesale transaction tariff to allow actual sales from the DG owner to the IOU?

5. Outstanding Interconnection and Related Technical issues

- In consideration of the issues addressed above, as well as the views expressed in Appendix A, which Rule 21 issues should be considered in the course of this rulemaking? What should be the order of priority? Parties should bear in mind that the CEC continues to coordinate the Rule 21 Working Group, and many of these issues may be best vetted in that process, before being brought into this formal docket.
- Is FERC's Notice of Proposed Rulemaking for small generation compatible with California's policies and procedures for DG?

6. DG Issues for the Future

- How can the Commission and CEC integrate the results of ratepayer-funded R&D in DG technologies into the utilities' planning and procurement process?
- What role should DG policy play, if any, in stimulating development of hydrogen-based electricity generation? Should this issue be considered in conjunction with the utilities' Low Emission Vehicle Programs, potentially employing hydrogen as a power source for both mobile and stationary applications?
- Which advanced DG technologies, such as fuel cells, microgrids and storage systems, should be actively considered in this proceeding? What specific resource needs could be met by these technologies, at present or in the near future? What policy issues, if any, must be addressed to effectively deploy these strategies?
- Finally, what is the potential for aggregating DG loads at the transmission level? How should the Commission coordinate with the utilities, ISO and other relevant entities to explore this potential?

XI. Proceeding Schedule

We seek the parties' comments on the questions posed in this proceeding no later than May 15, 2004. Reply comments are due no later than June 6, 2004. The assigned Commissioner and Administrative Law Judge will issue a final scoping memo at a later date following review of the initial round of comments and which elaborates on the procedures and schedule for this proceeding.

We anticipate that this proceeding will take no longer than 18 months to complete.

XII. Parties and Service List

This OIR is served on the parties in the following proceedings: R.02-01-011, R.01-10-024, R.99-10-025 and R.98-07-037. We also serve the OIR on the California Resources Agency, the California Environmental Protection Agency, and the Governor's Office of Planning and Research.

Within 20 days from the mailing date of this order, any person or representative of an entity interested in monitoring or participating in this proceeding should send a letter to the Commission's Process Office (Processoffice@cpuc.ca.gov) and to the Public Advisor's Office (Publicadvisor'soffice@cpuc.ca.gov), both of which are located at 505 Van Ness Avenue, San Francisco, California 94102, requesting that the person or representative's name be placed on the service list. The Process Office will thereafter create a new service list and the new service list will be posted on the Commission's web site, www.cpuc.ca.gov soon thereafter. Parties' request for inclusion on the service list should include an email address. Parties who do not contact the Commission for inclusion on the service list will not receive future documents in this proceeding.

In accordance with Commission practice, by entering an appearance at a hearing or by other appropriate means, an interested party or protestant gains "party" status. A party to a Commission proceeding has certain rights that non-parties (those in "state service" and "information only" service categories) do not have. For example, a party has the right to participate in evidentiary hearings, file comments on a proposed decision, and appeal a final decision. A party also has the ability to consent to waive or reduce a comment period.

Non-parties do not have these rights, even though they are included on the service list for the proceeding and receive copies of some or all documents. When individuals write to the Process Office to request to be on the service list, they should indicate if they wish to be an appearance, and if so, they should indicate how they intend to participate in the proceeding. Individuals who intend to maintain appearance or party status must appear at the prehearing conference to confirm this.

Any party interested in participating in this rulemaking who is unfamiliar with the Commission's procedures should contact the Public Advisor's Office in Los Angeles at (213) 576-7056, or in San Francisco at (415) 703-2074, (866) 836-7875 (TTY – toll free) or (415) 703-5282 (TTY).

XIII. Preliminary Categorization of the Proceeding

This proceeding is preliminarily categorized as quasi-legislative. We expect to conduct evidentiary hearings at this time. The final scoping memo issued in this proceeding by the assigned Commissioner will address the need for hearings on the basis of the comments of the parties. Parties who request hearings should describe the factual disputes evidentiary hearings would resolve.

Any person who objects to the preliminary categorization of this rulemaking, the need for hearings, or the issues raised in this preliminary scoping memo shall raise such objection(s) in comments to be filed ten days after the issuance of this order and pursuant to Rule 6(c)(2) and 6.4.

XIII. Ex Parte Communications

This proceeding is subject to Rule 7, which specifies standards for engaging in ex parte communications and the reporting of such communications. Consistent with that rule, for as long as this proceeding is categorized as "quasi-legislative," parties may communicate with decision-makers and are not required to notify other parties of those communications.

XIV. Electronic Service Protocols

The Commission will permit and encourage electronic service in this proceeding to mitigate the expense of participation. Parties should use the electronic service protocols attached to this order for all pleadings if they have access to electronic mail.

Findings of Fact

1. The Commission has expressed its support for the development of distributed generation by utilities and customers.

2. State policy and utility rules will affect the development of distributed generation.

Conclusions of Law

1. The Commission should initiate a rulemaking to consider policies, rules and practices that would promote the development of cost-effective distributed generation in California.

2. Pub.Util.Code Section 353.9, enacted in SB28x of 2001 requires the Commission to develop a cost-benefit methodology for analyzing distributed generation investments.

3. Because all of the issues remaining in R.98-07-037 will be addressed in this rulemaking, the record in R.98-07-037 should be incorporated into this docket and R.98-07-037 should be closed.

Therefore, **IT IS ORDERED** that:

1. A rulemaking is instituted on the Commission's own motion to establish policies, procedures and incentives regarding distributed generation and distributed energy resources, and to implement the provisions of Pub.Util.Code § 353.9.

2. PG&E, SCE and SDG&E shall file an update on their plans to incorporate DG into grid-side system planning, as required by Ordering Paragraph 2 of D.03-02-068. These updates shall be filed no later than two weeks from the date of this order.

3. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company are made respondents to this proceeding.

4. Proceeding R.98-07-037 is closed, and issues concerning the Self-Generation Incentive Program will be considered in this new docket. The record in R.98-07-037 is incorporated in this proceeding by reference.

5. The Executive Director shall cause this Order Instituting Rulemaking to be served on the respondents, the Executive Director of the California Energy Commission, the California Power Authority, the California Independent System Operator, the state Air Resources Board, the California Environmental Protection Agency, and on the parties to the following Commission proceedings: R.02-01-011, R.01-10-024, R.99-10-025, and R.98-07-037.

6. Within 20 days from the date of mailing of this order, any person or representative of an entity interested in monitoring or participating in this rulemaking should send a letter to the Commission's Process Office, 505 Van Ness Avenue, San Francisco, California 94102, or ALJ_Process@cpuc.ca.gov asking that his or her name be placed on the service list.

7. The category of this rulemaking is preliminarily determined to be "quasi-legislative" as that term is defined in Rule 5(d) of the Commission's Rules of Practice and Procedure.

8. The respondent utilities shall and interested parties may submit initial responses to the questions posed in Section IV no later than May 15, 2004. Reply comments shall be filed no later than June 6, 2004.

This order is effective today.

Dated March 16, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

APPENDIX A

Potential Topics for Consideration in CPUC DG OIR

A Report Submitted on Behalf of Some Rule 21 Working Group Members

Scott Tomashefsky
California Energy Commission
June 5, 2003

DISCLAIMER:

The comments contained in this paper represent a collection of thoughts from many participants actively involved in the Rule 21 Working Group. This paper is not intended to represent a consensus opinion of the Rule 21 Working Group nor does it present the positions of all entities involved in the Rule 21 Working Group process. It is merely presented as a range of topic areas, some of which have been previously litigated, for consideration by policymakers. While some parties of the Rule 21 Working Group disagree with some of the recommendations, the paper reflects the experience of many individuals who work within the distributed generation community on a regular basis.

Introduction

This White Paper is offered for the California Public Utilities Commission (CPUC) to consider in its upcoming rulemaking on distributed generation.

As general background, the Rule 21 Working Group includes members representing all aspects of the distributed generation community, with utility representatives, DG manufacturers, project developers, and regulators all represented in some form. Approximately 35 members actively attend meetings which are held approximately once every 4-6 weeks. Another 200 members track developments via an e-mail distribution list. Updated materials related to the Working Group, including meeting minutes, Rule 21 equipment certification information, as well as technical documents are available on the Energy Commission website at www.energy.ca.gov/distgen.

The Working Group process is overseen by the California Energy Commission, with technical support funded under contract via the Energy Commission's Public Interest Energy Research (PIER) program. To date, approximately $830,000 of public funding has been used to support the Rule 21 effort.

While the initial focus of the group was to craft a model Rule for the interconnection of distributed generation facilities installed and operated by utility customers, which it did during calendar year 2000, the group now meets for the sole purpose of improving the interconnection process. Issues are debated and addressed in varying degrees. Resolution of issues is often reached. In some instances, however, additional policy direction from policy-makers is required to resolve the issue.

This paper offers several thoughts in consideration of the upcoming DG rulemaking expected to be issued by the CPUC in the next few months. It is our expectation that the CPUC will continue to work closely with the Energy Commission in crafting the OIR, continuing its productive working relationship on DG issues and consistent with the recently approved Energy Action Plan.

Interconnection Issues to Consider in OIR

Export Issues

Issue: Should Rule 21 guide and regulate the interconnection of all generating facilities subject to the jurisdiction of the CPUC?

Rule 21 does not currently restrict generating facilities from exporting energy to a utility's electric system. Rule 21 does, however, establish procedural and technical requirements for evaluating and controlling the impact of such energy exports and allocating the costs and responsibility for addressing such impacts.

The requirement in R.99-10-025 to establish standardized and streamlined interconnection requirements led the Rule 21 Working Group to initially focus on requirements and procedures for smaller customer generating facilities that did not (by design) or could not (due to relative size) export power to the utility's electric distribution system. Establishing the assumption that a generating facility would not feed significant power back into the utility's system allowed for the simplification of the review process regarding the impact the generation may have on the utility's system and the specification of simpler, lower-cost protection systems. This initial focus has led some to believe Rule 21 does not permit customer generation to feed power into a utilities distribution system under any circumstance. This was not intended to be the case.

The requirements for non-exporting customer generation installations are fairly well established. As such, some parties contend that the Rule should be expanded to specifically identify and establish requirements for customer generation that export energy (either intentionally or inadvertently) onto a utility's electric system, but under circumstances that are not subject to interconnection requirements established by the FERC. Such circumstances currently include net energy metering programs established under Section 2827 of the Public Utilities Code, power purchase requirements for Qualifying Facilities with a nameplate capacity of 100 kW or less as set forth in D.96-10-036, or the "inadvertent energy delivery" arrangements negotiated between a customer and the utility.

The Rule 21 Working Group technical subgroup is currently debating the issue and focusing on three primary areas:

- *What level of power should be allowed to be exported under the simplified interconnection provisions of Rule 21?*
- *What additional protective and operational requirements should be included in Section D of Rule 21 to safely control any electric power deliveries to utility electric systems?*
- *Should the Rule's Supplemental Review process be revised to more effectively accommodate the export of electric power?*

Policy direction affirming the scope and applicability of Rule 21 is paramount to its continued success, especially in light of the expectation that the FERC will eventually issue its NOPR on small DG interconnection issues. Care must be taken to identify and coordinate the regulation of customer generation interconnection requirements between the CPUC, the California Independent System Operator (CAISO), and FERC. The utilities' administration of Rule 21 is currently based on the assumption that the interconnection of generation engaged in any transaction regulated by the FERC is subject to FERC interconnection requirements, and that by satisfying those requirements, any interconnection requirements established by the CPUC will also be satisfied.

Metering Issues

> **There has been much discussion over the language contained in Section F of Rule 21, which addresses Metering and Telemetry requirements. The arguments can be narrowed down to two primary issues: 1) whether utilities should require third-parties to purchase and/or use utility-grade meters; and 2) the extent of information required by the utilities from the DG facility to administer its tariff obligations.**

> **The Rule 21 Working Group debated these issues with the intent of resolving them under the current rule structure. After several months of discussion ending in late 2002, the Working Group concluded that policy reconsideration is necessary to resolve the issue. In summary, the utilities are requiring utility-grade meters 100 percent of the time, which complies with the current language in Rule 21. Other parties believe this requirement is too stringent and should be revisited. Each of these issues is summarized briefly below.**
>
> **Issue #1: Should each new customer be financially responsible for the installation, operation, and maintenance of utility-supplied billing-grade metering on all new customer generation units?**

Most customer generation facilities are supplied with a meter or other measurement function to record the amount of power produced by the generating facility. Such measurement devices may or may not be of utility grade accuracy but is typically satisfactory for the needs of the customer. The data provided by such metering is produced in various formats. The utilities contend that, due to the uncertainties in accuracy and the incompatibility of data formats, installation of a utility meter is required to measure the output of the customer's generator for billing departing load charges and acquiring data needed for the operation and planning of their electric systems.

Parties are concerned about the generation output meter and the utilities' discretion to require a meter they control and choose to be used even if a third party provider or customer has installed a utility-grade meter that meets utilities specifications and allows access to tariff-approved billing data. For these customers, the cost of the meter imposes an additional $4,000 - $10,000 installed cost per project.

Some parties assert the ability to install metering that will meet both the utilities' needs as well as the needs of the customer generator. Given the correct controls for the accuracy and security of the information to be supplied by a customer or third-party metering provider, and the ability to integrate the data provided into the various utilities' billing systems, the utilities indicate an openness to consider third-party metering and have suggested that the third-party metering provisions of Rule 22 may be used as a basis for developing similar opportunities for customer generation metering requirements

Under Section F.2 of the current Rule 21 language, ownership, installation, operation, reading, and testing of metering shall be by the utility except to the extent that the CPUC determines that all these functions, or any of them, may be performed by others as authorized by the Commission. Many parties believe the new proceeding is the appropriate forum to revisit this issue globally.

Issue #2: What metering information should utilities have access to for tariff administration, planning, and operations?

The utilities interpret the language of Rule 21 allow them to require net generation metering on all generating units in their territory. For purposes of tariff administration, the utilities argue that the ability to precisely determine the amount of electric service supplied to a customer in order to administer various applicable electric service tariffs and charges supports mandatory installation of customer generation metering. PG&E identified, in working group meetings, four needs for such metering that are related to the tariff administration: 1) non-bypassable charges; 2) standby charges; 3) gas cogeneration rates; and 4) self-generation incentives. PG&E also identified four reasons that non-metering alternatives are now at issue: 1) gaps in information; 2) the need for manual input of data; 3) customer reluctance to provide proprietary data; and 4) data integration issues.

SCE cites the need to assess nuclear decommissioning charges and public purpose program charges as a basis for requiring revenue quality metering on customer generation. Specifically, SCE argues that there is no common format for the information provided as an alternative to generator metering, thus inhibiting its ability to re-integrate data easily. Moreover, SCE suggests that some customers are reluctant to have tariffs administered on estimated usage and thus raises the issue of an electric utility's obligation to accurately bill their customers.

SDG&E argues that past and current Rule 21 language allows it to require net generation metering of all customer generation. SDG&E's position is that it should continue to require such metering on all new customer generation. While it appears that SDG&E may not conform its practice to the reporting requirement in Section F paragraph 3, SDG&E confirms that it only installs metering on customer generation to administer its tariff provisions.

During deliberations, parties argue that the utilities should demonstrate an overwhelming need for net generation metering before metering is mandated. In any event, parties assert that utilities should only require net generation metering to administer a tariff "to the extent that less intrusive and / or more cost effective options for providing the necessary Generating Facility output data are not available."

The utilities agree that their metering requirements are implemented on a prospective basis and that customers already connected will not be subject to changed metering configurations. Parties argue that the planning and operation of the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems; or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the Point of Common Coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, planning and operation concerns may not justify net generation metering.

Dispute Resolution Process

Issue: Is the current dispute resolution process contained in Section G of Rule 21 adequate to resolve differences between utilities, customers, or other parties planning and designing DG installations?

The resolution of disputes between stakeholders with regard to DG is outlined in Section G of Rule 21. The Rule offers a process similar to one used when customers have billing disputes with their local utilities. To date, there has been one formal complaint that has gone before the CPUC with many others addressed informally between parties. While the previous statement may suggest that the process is working well, parties have expressed high levels of frustration about how difficult it is to resolve issues short of filing a formal complaint. In some cases, parties have claimed that resolution of differences over protection and operation requirements cannot be reached and the projects are cancelled.

For example, the Rule 21 working group has struggled with the issue of anti-islanding and how much protection is required by utility protection engineers. The working group in its deliberations has concluded that the protection engineers have substantial discretion to determine the level of protection required. While consistent with Rule 21 language, parties seek alternative approaches to challenge the issue further. An enhanced dispute resolution process with some level of binding authority could help resolve this and similar issues, provided that the process should not be focused on finding ways to lessen utility discretion in maintaining the safety and reliability of the distribution system.

The Rule 21 working group is revisiting this issue to determine ways to improve the process. Presently, it is looking at a number of models, including a dispute resolution process proposed in Massachusetts as that state develops interconnection rules. There is no consensus among the working group as to the effectiveness of the current dispute resolution process.

Interconnection Fees/Costs

Issue: Should the interconnection fee schedule established in Rule 21 be revisited now that California has more than two years of experience with a combined $1400 application fee limit for initial and supplemental review?

During the development of Rule 21 in 2000, the working group deliberated extensively about what an appropriate fee might be assessed to customers looking to interconnect. During initial deliberations, discussions focused on the disparity between interconnection costs for small and large systems. At that time, the group determined that, rather than determine a per kW costs, an single hour/cost estimate was determined with the belief that the CPUC might establish a size or technology-based cost structure in the future.

Based on this discussion, the CPUC adopted the group's recommended guidelines of $800 for initial reviews (simplified interconnections) and an additional $600 for supplemental reviews. Subsequently, the working group reached two general conclusions: 1) the $1400 fee needed to be revisited at some point; and 2) the fee should not represent a barrier to DG deployment.

In a related matter, several parties believe there is a need to establish standard reporting and data requirements to track the cost of the interconnection reviews, studies, and related administrative costs. They suggest that the CPUC should review each transaction from the utility and the developer side of the ledger, subsequently establishing caps for each interconnection cost. Included in the evaluation would be administrative, ancillary, interconnection study costs, excluding only labor and capital equipment costs. These costs and current data of all DG interconnected under Rule 21 could be better coordinated with Energy Commission integrated resource planning as well as CPUC revenue, procurement and General Rate Case procedures. Agreement has not been reached as to who should be responsible for the costs of collecting and reporting this information.

Interconnection Rules for Network Systems

Issue: Can simplified interconnection rules be created for network systems?

Simplified interconnection rules for spot and grid secondary network systems do not exist in the context of Rule 21. As such, DG projects proposed in network system areas such as downtown San Francisco require costly interconnection studies and often require expensive equipment to complete the interconnection. Due to the complexity of the studies required and the lack of information related to impact of interconnecting generation into a networked system, these costs can exceed $50,000 per project. It is possible that cost allocation or recovery rules could be determined in the upcoming OIR and eventually implemented as part of the utilities general rate cases.

Non-Interconnection Issues to Consider Including in New DG OIR:

Objective: The issuance of D.03-02-068 left many DG-related policy issues unresolved. Much has changed with respect to public policy direction related to DG. The following section represents some potential issues to consider.

Determine a standard definition of DG. While the last proceeding established a definition of DG, it is appropriate to reconsider the definition in light of the many rules, regulations, and state policies that use a DG definition. In each forum, the definition is slightly different, a problem that is national. What is DG to one person is not to another. Some parties argue that there should be a standard definition of DG while others argue that due to various legislatively derived definitions, developing just one definition for DG is impractical and serves little purpose.

Determine if utility system performance would be enhanced or if ratepayers would realize economic benefits by incenting utilities to deploy DG. The previous rulemaking offered provisions for utility ownership of DG but did not offer any significant approaches for the effective deployment of DG on the utility side of the meter. With a present directive to consider DG in its planning activities, the CPUC could use this OIR to determine if integrating DG into its resource planning activities would benefit utility ratepayers. Close coordination should be made with R.03-03-015, which is currently investigating whether added rates of return should be afforded to DG.

Perform more extensive cost/benefit analyses. This issue was largely ignored in the first proceeding. A potential list of cost and benefit issue areas includes treatment for capacity value, unexpended energy, transmission line delay, avoided distribution investment, and avoided T&D losses. Beyond the traditional cost/benefit measures, system benefits issues such as locational and operational benefits related to waste heat utilization, demand reduction, avoided emissions, and thermal energy production could be evaluated. The Energy Commission's PIER program is currently undertaking several areas of DG research with results that can feed directly into the cost/benefit analysis that should be addressed in this proceeding. The OIR should identify these areas and then explain how the research will be used in the policy context. The DG OIR and its final determination of cost and benefits with order to findings of fact should be officially tied to final decisions of the utilities' future general rate cases and procurement proceedings.

Some parties believe that any examination of DG benefits should make a clear distinction between those that accrue to utility ratepayers in general and those which accrue to the DG operator alone. In addition, many of these parties agree that any cost/benefit analysis include all of the costs related to DG, including those costs shifted to others through incentive programs, exemptions, net metering tariffs, tax credits, etc.

<u>Further evaluate terms of physical assurance.</u> Some parties recommend that the CPUC further evaluate physical assurance with respect to standby tariff rate design. In the context of non-coincident peak demand in some cases, it may not be necessary to require physical assurance to avoid standby charges. The issue centers on whether a utility truly needs to add infrastructure to meet the noncoincident peak of all customers at all times. The debate is similar to the reserve capacity issue being debated for the California transmission grid.

<u>Evaluate effectiveness of CPUC Self-generation Program.</u> The CPUC's Self-generation Program, a $500 million, four-year program designed to provide incentives for the effective deployment of DG has been operating for nearly two years. Many stakeholders have concerns about the cost-effectiveness of the program. The OIR provides an opportunity to review its effectiveness which can then be used in determining whether to extend the program beyond 2004. Please note that the Legislature is currently considering extending the program for at least two years. It should also be noted that no cost recovery mechanism has been adopted for recovery of the program's costs. The following are suggestions for consideration in the OIR:

a. **Public review of interconnected DG last 5 years.**

b. **Review of installation costs versus generation capacity – cost-effectiveness, reliability, geographic disbursement, etc.**

c. **Review and realignment of eligibility criteria -- (performance-based rather than technology-based and then a re-establishment of technology-eligibility process underway to ensure that process in rule is set to determine performance (emission, rated capacity, efficiency)**

d. **Payment should be based on capacity installed not eligible project cost, with incentive levels adjusted downward to reflect observed installed costs**

e. **Review and ensure equipment that converts a cogeneration system's waste-heat to useful thermal output should be eligible**

for payment. Establish ongoing compliance criteria and verification process.

f. **Compare costs and benefits of capacity added to the grid system resulting from the program to other available sources of new capacity. This comparison would be performed to establish the rationale for extending the program and committing additional ratepayer funds.**

g. **Insurance requirements for the program are more strenuous than for interconnecting systems and should be evaluated.**

h. **Annual reports could be provided to Legislature.**

In performing this analysis, close coordination with the CPUC's Energy Division analysis pursuant to CPUC Decision 01-03-073 is critical to ensure that duplication of effort does not occur.

<u>Ensure that communications between utilities and customers regarding customer generation options are appropriately balanced.</u> Some stakeholders claim utilities are using various tactics to convince customers to retain utility service and not select a DG option. The utilities strongly disagree with these claims and have indicated that, as the current provider of electricity, they have the right and obligation to provide factual economic and educational information to their customers and that doing so is in no way anti-competitive. The utilities have further said they have not and will not attempt to convince their customers to change their decisions to install DG once an agreement to procure DG equipment is reached. It is generally agreed upon that anti-competitive behavior by any of the parties should not be allowed.

(END OF APPENDIX A)