D99-10-065

SEE BOX

COPIES TO SELL

Mailed 10/25/99

Decision 99-10-065 October 21, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking on the Commission's Own Motion to Solicit Comments and Proposals on Distributed Generation and Competition in Electric Distribution Service.	Public Utilities Commission Rulemaking 98-12-015 (Filed December 17, 1998)

OPINION REGARDING DISTRIBUTED GENERATION AND ELECTRIC DISTRIBUTION COMPETITION

TABLE OF CONTENTS

OPINION REGARDING DISTRIBUTED GENERATION AND ELECTRIC DISTRIBUTION COMPETITION

I. Summary

This Order Instituting Rulemaking (OIR) was initiated on December 17, 1998, to consider the impact of the anticipated deployment of distributed generation on California's electricity distribution system, and to consider whether reforms are needed with respect to the regulatory framework which governs electricity distribution service.[1] Distributed generation enables siting of electric generation technologies in close proximity to the load.

In recognition of the different oversight responsibilities inherent in this task, the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the Electricity Oversight Board (EOB) decided to work in a collaborative manner to address the issues at hand. The CPUC opened this OIR, and the CEC and the EOB opened their respective dockets.[2]

Today's decision provides a roadmap which outlines how the CPUC, in cooperation with the CEC, the EOB, and the Legislature, plans to address the issues surrounding distributed generation, distribution competition, and the role

[1] Although the focus and the caption of the OIR was principally on distributed generation and distribution competition, the OIR also solicited comment on whether there should be a broader, more comprehensive review of the role of the utility distribution company (UDC), and what the ultimate role of the UDC should be in a restructured electric industry.

[2] The CEC's docket number is 99-DIST-GEN(1), and is entitled "Information Docket on Distributed Generation and Competition in Electric Distribution Service." The EOB's docket number is 99-A-1-DG, and is entitled "Administrative Docket on Distributed Generation."

of the UDC in the competitive retail electricity market.[3] This decision bifurcates the issues raised in this OIR into two tracks. The first track will address the issues pertaining to distributed generation. The CPUC is opening a new rulemaking, R.99-10-025, to address this track. The second track will address the distribution competition issues, and the role of the UDC in a competitive retail electric market. The second track will be handled initially in a CPUC staff study and report.

Although we recognize that distributed generation impacts many facets of distribution competition, we believe that current market forces and changes in technology require us to address the distributed generation issues first so that it can be facilitated. To facilitate the deployment of distributed generation, the CPUC needs to address the following: interconnection issues; who can own and operate distributed generation; what impacts, if any, will distributed generation have on the environment; the role of UDCs in distributed generation; and the rate design and cost allocation issues associated with the deployment of distributed generation facilities. Therefore, we are opening a new rulemaking today into these specific distributed generation issues, in collaboration with the CEC and the EOB. The current OIR will be closed.

With respect to the track two issues, there is a need to further examine the issues surrounding the emergence of competition with respect to distribution

---

[3] In the restructured electric environment, the investor-owned utilities (IOUs) retain ownership, maintenance, and operational responsibility over the electric lines that distribute electricity to their end-use customers, as well as to direct access customers. (Decision (D.) 95-12-063, as modified by D.96-01-009 [Preferred Policy Decision], p. 85; D.97-05-040, pp. 5, 48.) The use of the term "UDC" in this decision refers to the utility's role in the distribution system, while the term "IOU" is used to refer to the investor-owned utilities in a broader context.

services and retail electric services. Those issues include: considerations as to what the distribution system of the future may look like; whether distribution services should be unbundled and, if so, to what extent; what, if any, changes are needed with respect to the current statutory authority for irrigation districts, municipal utilities, and other publicly owned electric utilities; what the role of the UDCs should be in a competitive retail market; and whether the current market structure for the provisioning of default services and the procurement of electricity should be changed.

This decision directs the CPUC's Division of Strategic Planning (DSP) and the Energy Division to study and consider competition in distribution services and competition in the retail market, and to develop a report on the different policy options that the CPUC, in cooperation with the Legislature, can pursue. That report shall be available on or before April 21, 2000. Following the issuance of the report, we envision that the CPUC will open one or more new proceedings to address the distribution competition issues, and competition in the retail electric market.

II. Background

This OIR was initiated in December 1998 to consider whether the CPUC, in collaboration with the CEC and EOB, should pursue reforms in the regulatory framework governing electricity distribution service. In particular, the OIR focused on the gathering of information about the issues concerning distributed generation and distribution competition. Instead of creating new policies in this OIR, the intent was to identify the range of issues associated with these concepts, and to allow the CPUC, the CEC, and the EOB to develop a roadmap for addressing these issues.

The impetus for this OIR grew out of the efforts of various industry participants who were looking into the use of distributed energy resources (DER) [4] in a competitive electricity market. In April 1996, the CEC sponsored a roundtable discussion on distributed generation. As a result of that discussion, the California Alliance for Distributed Energy Resources (CADER) was formed in October 1996. The members of CADER represent a cross section of industry participants and state and local governments with an interest in distributed generation and its ramifications.

The members of CADER discussed and identified many of the operational, regulatory, and legislative issues associated with distributed generation. In a June 5, 1998 letter, 23 signatories, including CADER members, requested that the CPUC open a rulemaking into the role of the UDCs with respect to facilitating distributed generation, and the unbundling of energy and ancillary services injected directly into the distribution system. In response, the CPUC hosted a roundtable dialogue on distributed generation on August 3, 1998.

In 1998, the CPUC also adopted several resolutions which addressed distribution competition issues. In Resolution E-3528, the Commission adopted a resolution which opined that the reorganization of the Patterson Water District into an irrigation district that provides electrical services to existing and new industries within its boundaries did not substantially impair Pacific Gas and Electric Company's (PG&E) ability to provide adequate electrical service at reasonable rates in the remainder of PG&E's service territory. The resolution stated that even if the irrigation district constructed duplicate distribution facilities, such facilities provide:

---

[4] The term "DER" is discussed later in this decision.

> "a competitive check on the ability of the utility to pass through unreasonable costs through to ratepayers in distribution rates and provides discipline to both the utility and the Commission in determining the rate design for distribution services.... In addition, the provision of duplicative systems in this area will increase the level of competition available to customers in this area, even those that remain with PG&E." (Resolution E-3528, p. 6.)

Similarly, in Resolution E-3549, the CPUC adopted a resolution which opined that the formation of the McAllister Ranch Irrigation District would not substantially impair PG&E's ability to provide adequate service at reasonable rates in PG&E's remaining service territory.[5]

During the CPUC's deliberations on Resolution E-3549, some of the CPUC Commissioners raised the question as to whether the CPUC should consider a more general approach toward distribution competition, and how the formation of irrigation districts might impact its competition policies. The CPUC also noted that a relationship between distribution competition and distributed generation might exist. The CPUC staff was asked to reflect on these issues, and to recommend a future course of action. This OIR was the result of the staff's reflection.[6]

---

[5] In PG&E's comments to this request for an opinion of the effect of the proposed formation of the irrigation district, PG&E requested that the Commission open an investigation to "thoughtfully explore all the implications of increasing distribution competition, and not simply address these issues in a piecemeal fashion." The resolution recommended that PG&E's request to open an investigation be denied without prejudice. (Resolution E-3549, p. 6.)

[6] As indicated above, the CEC and the EOB opened their own dockets to consider these issues as well.

Appendix A of the OIR set forth a series of questions that the parties were asked to respond to. The OIR requested comments on the role of the IOUs with respect to the planning, ownership, dispatch, interconnection, and utilization of distributed generation. In addition, parties were asked for their views on whether generation and ancillary services at the distribution level should be unbundled, and what the future role of the UDCs should be. In the Assigned Commissioner's Ruling (ACR) of February 22, 1999, the parties were also asked to include in their comments their assumptions regarding the costs of distributed generation and storage technologies, the current commercial status of those technologies, and the projected status of those technologies over the next five to ten years.

In response to the OIR, a large number of comments were formally filed with the CPUC's Docket Office. Several entities that responded to the OIR did not formally file their comments with the Docket Office. We have, however, reviewed and considered those comments as well, and made them part of the Commission's correspondence file for this OIR. The parties also had the opportunity to file replies to the initial comments.

Since the purpose of this OIR was to gather additional information, we have generally refrained from summarizing the position of each party. Instead, this decision summarizes the concepts that the parties addressed. The positions that parties have taken fall into six general perspectives. They are: (1) the IOUs; (2) the publicly owned utilities;[7] (3) manufacturers and vendors of DER; (4) consumer groups; (5) environmental groups; and (6) builders/developers.

---

[7] The use of the term "publicly owned utilities" refers to local government entities such as municipal utilities, public utility districts, and irrigation districts.

A full panel hearing was held on June 1, 1999, in San Francisco. The issues were divided into the following four panels: (1) distributed generation market development; (2) distribution competition: definitions and related issues; (3) roles and responsibilities of the UDC: clarify broad policy issues; and (4) process: next steps. (See May 10, 1999 ACR Regarding Joint Agency Full Panel Hearing.) The full panel hearing was presided over by the CPUC Commissioners, two Commissioners from the CEC, and the Executive Director of the EOB. An opportunity was provided to all parties to file written responses to the questions that each panel was asked to address at the full panel hearing.

The draft decision of the assigned Commissioner Henry M. Duque and the assigned Administrative Law Judge (ALJ) John S. Wong, was mailed to the parties on September 21, 1999, in accordance with Pub. Util. Code § 311(g) and Rule 77.1 of the Commission's Rules of Practice and Procedure.[8]

Comments and reply comments to the draft decision were filed. We have considered these comments and have made appropriate changes to the decision. To the extent the comments reargued positions taken by the parties in earlier pleadings, we have not given them any weight in accordance with Rule 77.3.

III. Procedural Issues

A number of different motions were filed or submitted in this proceeding. Except as specifically noted in this decision, all of the motions that have been filed in this proceeding have been addressed in an ACR or in an ALJ's ruling.

---

[8] Unless otherwise noted, all code section (§) references are to the Public Utilities Code (Pub. Util. Code).

IV. Purpose of this Rulemaking

This OIR is part of the CPUC's continuing effort to bring competition to the regulated electric services industry. Foremost among the changes was to provide end-users with "the broadest possible array of choice in which the former 'ratepayer' can function as an intelligent, self-interested 'customer.' " (Preferred Policy Decision, pp. 5-6.) To create this change, the generation sector was opened to full competition, the IOUs began to divest themselves of their interests in generating assets, the Power Exchange was created to act as a spot market for the trading of electricity, the Independent System Operator (ISO) was created to take over the scheduling and dispatch operations of the transmission system, and end-use customers were allowed to choose their electric service provider (ESP) through direct access.

The emergence of distributed generation and DER as viable options, is likely to change the way end-users obtain electricity and the way generation occurs. The ability to generate one's own electricity is a continuation of customer choice, as well as a competitive alternative to bundled distribution service and direct access. Instead of relying on electricity coming from distant, large central generating stations, some end-users may choose to site distributed generation on their own premises. In doing so, the end-user may bypass the transmission and distribution (T&D) facilities altogether, or it may rely on the T&D facilities for standby service only. In addition, the IOUs may be able to use distributed generation to meet distribution system needs.

Distributed generation is not a new concept. At the most basic level, emergency power generators are a form of distributed generation. In recent years, the proliferation of qualifying facilities (QFs) have resulted in additional sources of distributed generation. Internal combustion engines, microturbines, wind turbines, and photovoltaics are just some of the distributed generation resources that are currently being deployed. In the future, fuel cells and various kinds of energy storage technologies are likely to be employed as additional alternatives.

In Section 330(b), the Legislature declared that "reductions in the price of electricity would significantly benefit the economy of the state and its residents." The Legislature also declared in § 330(e) that:

"Competition in the electric generation market will encourage innovation, efficiency, and better service from all market participants, and will permit the reduction of costly regulatory oversight." Both of these legislative declarations can be realized with the entry of distributed generation as a competitive alternative to central power production.

Although the distributed generation market presently accounts for only a minimal share of the total electricity generated for consumption in California, most of the parties to this proceeding believe that the distributed generation market can grow substantially over the next ten years. In addition, other alternatives to bundled electric distribution service are beginning to emerge. Because of these changes, the CPUC needs to review the current regulatory framework, and determine whether changes are needed to eliminate the barriers that might unduly discourage the deployment of DER, and to consider what other changes are needed to respond to competitive pressures in the electric distribution and retail markets.[9]

---

[9] Texas and New York are currently studying the interconnection issues associated with distributed generation.

In opening this OIR, we recognized that the issues relating to distributed generation may also relate to distribution competition. That is, if the market for the installation of distributed generation devices is opened up to end-use customers and other entities, this may result in competitive alternatives to the IOUs' existing electric distribution services and facilities. Given the potential impact of distributed generation on the IOUs' distribution function, this OIR was initiated to gather information on both topics, and their interrelationships. In addition, the OIR recognized that the formation of irrigation districts and other publicly owned utilities also have implications for distribution competition. The OIR was opened to examine all of these issues, and to develop proposals to further reform the regulatory framework in a manner that ensures consistency with the objectives and goals regarding the restructured electric industry as perceived by the CPUC and the Legislature.

We were also cognizant of the fact that the IOUs are no longer the vertically integrated utilities that they once were. Because of this, we need to examine whether the monopoly model is still viable in a more competitive environment. In addition, the current rates, rules and tariffs were largely written with a monopoly provider of services in mind. In order to fully realize the benefits of the new market structure, we need to rethink the rates, rules and tariffs, and consider changes to them.

If we fail to make timely and necessary changes to our current regulatory framework, we may find ourselves in a situation where technological advancements cannot be implemented because of existing regulatory barriers. Such an outcome is not desirable. The regulatory structure needs to adapt to the technological and policy changes that are taking place.

In order to update our regulatory approach, we embarked on an information gathering process through this OIR to aid us in identifying the various issues, and to help frame proposals for future action. This decision reflects the results of this collaborative effort with the CEC, the EOB, and the industry participants. In the sections which follow, we discuss the specific issues that were raised in the OIR, and our thoughts on how these issues should be addressed on a going forward basis.

V. Bifurcation of the Issues

In the OIR, we requested comments on the following two questions which touched on what we believe to be the relationship among distributed generation, distribution competition, and the UDC's role in the retail electric market:

1. From a policy perspective, does consideration of DG necessarily require a broader, more comprehensive look at distribution competition and the role of the UDC?

☆☆☆

12. What procedural steps should be pursued? Should there be a more focused analysis of DG issues, or a more comprehensive consideration of issues surrounding distribution competition? Are there issues which are more appropriately considered in workshops, full panel hearings, and/or other procedural forums?

Most of the parties who commented expressed broad support for distributed generation, and recommended that the distributed generation issues be considered before the distribution competition issues are addressed. These parties generally agreed that distributed generation has an important role to play in supplying electricity to end-use customers and to the distribution grid. These parties were also in near unanimous agreement that interconnection standards must be developed in order to facilitate the interconnection of DER to the distribution grid.

Most of the parties also agreed that the distribution competition issues are more complex and cannot be readily addressed because of existing conditions and statutes. They recommend that a review of the distribution competition issues take place after the distributed generation issues are resolved.

Based on the comments, and our analysis of the various issues, we believe that the issues raised in this OIR can be bifurcated into two separate tracks. The first track are those issues that can generally be categorized as distributed generation issues. The second track of issues are those that address the broader issue of distribution competition, and what the role of the UDC should be in a competitive electric retail market. We also conclude that there are some issues which have an influence on both distributed generation and distribution competition. These issues are the UDC's role, what services, if any, are to be unbundled, and rate design.

We also believe that the first track, addressing the distributed generation issues, needs to be resolved quicker than the distribution competition track because distributed generation technologies are available for use today. If we delay addressing the distributed generation issues, the likely result is that end-use customers will either: (1) not be able to interconnect distributed generation on their property to the UDC's distribution system; or (2) that end-use customers may encounter barriers and delays in the interconnection of their distributed generation to the UDC's distribution system. Neither of these outcomes are beneficial from the perspective of providing end-users with a choice of electric supply, and the opportunity to reduce their electricity costs.

Therefore, the CPUC will open a new rulemaking to address the issues concerning distributed generation. The CPUC will collaborate with the CEC and the EOB to develop recommendations for statutory changes, and to resolve other issues within the purview of the three agencies. As noted in the text of this decision, a workshop process will be established to address the interconnection issues. In addition, workshops will be held on how the UDCs can identify and incorporate the level of DER deployment into the distribution system planning process, and whether certain types of distributed generation facilities can qualify for some form of streamlined CEQA review at the local level. All of the other issues in distributed generation will be handled in the form of prepared testimony and in formal hearings. The procedural details of the workshops, and how the other distributed generation issues are to be addressed, are set forth in the new rulemaking.

The second track will address the various issues related to distribution competition and the role of the UDC in the competitive retail electric market that we discuss later in this decision. These issues will be addressed in a CPUC staff study conducted by DSP and the Energy Division.[10] We believe that further staff study is needed to assist us in developing more concrete proposals as to what the future of distribution competition should look like, and what role the UDCs should play in the marketplace. Further study of these issues in track two are appropriate because existing statutes limit the types of initiatives that the CPUC can pursue at this time.

The study shall examine proposed strategies to address these issues. The CPUC staff may hold workshops, roundtables, or other informal discussions, with input from all customer classes, to gather information. The staff shall then prepare a report for the CPUC no later than April 21, 2000. Copies of the report shall be served on the parties in the new rulemaking on distributed generation. The CPUC will then consider the report, confer with the Legislature, and decide

---

[10] The CEC has indicated that it may participate in the distribution competition issues as an interested party. The EOB has indicated that it has no interest at this time in the distribution competition issues. Accordingly, the staff study and report will be exclusively a CPUC effort.

what procedural vehicles should be used to further address the issues and strategies identified in the staff study. Once a new procedural vehicle is identified, interested persons will have an opportunity to provide written comments on the issues and strategies raised in the staff report.

The two tracks described above provide a procedural roadmap as to how the CPUC plans to address all of the issues raised in this OIR. Therefore, this proceeding shall be closed.[11]

In the sections which follow, we discuss the specific issues that were raised in the OIR, and our thoughts on how these issues should be addressed on a going forward basis.[12]

VI. Distributed Generation and Distributed Energy Resources

A. Definition of Distributed Generation and Distributed Energy Resources

In this decision we use the term "distributed generation" to refer to those small scale electric generating technologies such as internal combustion engines, microturbines, wind turbines, photovoltaics, and fuel cells. We use the term DER to refer to the distributed generation technologies, storage technologies, end-use technologies and DSM technologies.

---

[11] Since this docket is to be closed, the May 27, 1999 motion of PG&E, and the motion of San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) for evidentiary hearings are moot.

[12] The list of issues described in the following sections should not be viewed as precluding other relevant issues from being considered. Should other issues related to distributed generation, distribution competition, or the role of the UDC, come before us in either of those two tracks, the CPUC will consider on a case-by-case basis whether those issues should be addressed.

"Distributed generation" has also been referred to as "distributed energy resources" (DER) or "distributed resources" (DR). (OIR, p. 2, fn. 1.)[13] DER appears to be the broadest of all three terms, and includes distributed generation, as well as energy storage technologies such as battery energy storage, superconducting magnetic energy storage, flywheel energy storage, and compressed air energy storage. DER can also refer to targeted "end-use technologies" or targeted DSM techniques.

In general, a DER has the following attributes: the DER is usually located at or near the load center; it may be connected to the distribution system or it can operate independently of the distribution system; it provides an enhanced value other than its energy and capacity; the DER is usually small in terms of electric power output; and the DER facility is usually automated, modular and mass produced.

While there appears to be general agreement among the parties on the types of generation technologies that can be broadly classified as distributed generation, there were differing views on the range of technologies that should be considered for the purposes of developing interconnection tariffs. Some parties favor a broader focus on DER, while others propose consideration of generation and storage technologies, but not DSM technologies. In addition, parties have proposed various size limitations for the generation technologies that should be included in the definition of distributed generation.

---

[13] In footnote 1 of the OIR, we stated that distributed generation "generally refers to generation, storage, or demand-side management (DSM) devices, measures, and/or technologies that are connected to or injected into the distribution level of the transmission and distribution (T&D) grid...."

We believe that a common definition of distributed generation and DER for purposes of the new rulemaking on distributed generation is necessary to guide the development of interconnection standards and rules. Also, we believe that there is a need to explore whether a size limitation for distributed generation should apply. We propose for discussion that distributed generation facilities be limited to a size of 20 megawatts (MW) or less. The 20 MW or less proposal is based on: (1) the size of distributed generation that is suitable for supporting distribution substations; (2) the limit is best suited for standardized interconnection and permitting; and (3) this range is most likely to be used for customer-side generation. As discussed in the interconnection section of this decision, a workshop on interconnection standards should be held in the new rulemaking on distributed generation. We expect the workshop process to consider whether the interconnection tariffs require uniform definitions, and also whether the proposal for a size limitation for defining distributed generation is appropriate.

B. The Benefits and Disadvantages of Distributed Generation

A number of different parties have commented on the possible benefits of distributed generation. These benefits could include the following: wider customer choice; the distributed generation facilities can provide backup service, or provide all of the electric needs of the end-user; the cost of installing and operating the distributed generator may be lower than the current cost for electricity; the facilities can improve the end-user's power quality and reliability; distributed generation facilities may improve system reliability and may reduce T&D line losses; the installation of such facilities may result in the avoidance or deferral of distribution system investments; the siting of distributed generation facilities may provide relief to constrained distribution systems; and there may be environmental benefits depending on the type of technology employed and the type of fuel that is used.

The above-mentioned benefits, however, have been challenged by several parties. The IOUs state that not all distributed generation facilities will improve reliability and enhance the power quality on the distribution system because the benefits depend on where the distributed generation is located. The California Manufacturers' Association (CMA) points out that distributed generation facilities that are not connected to the distribution system provide fewer benefits to the distribution system than distributed generation facilities that are interconnected to the distribution system.

Regarding the environmental benefits of distributed generation, some parties state that many of the distributed generation technologies are cleaner than the central station generators. As more environmentally friendly distributed generation technologies are deployed, they may reduce or displace the use of central station generators, which are perceived to have more of a negative impact on the environment. Also, depending upon where the distributed generation facilities are located, such facilities may reduce the need for upgrades and improvements to the distribution system.

Other parties commented that the deployment of distributed generation may have adverse environmental effects. If large numbers of fossil fueled distributed generators are sited in the same area, air quality problems may be exacerbated rather than reduced. As some of the parties point out, many small distributed generation applications are not covered by existing air quality regulations. If large numbers of these small distributed generators are sited in the same general vicinity, the cumulative effect of such deployment may adversely impact the air quality.

In addition, renewable technologies such as wind power and photovoltaics can require large amounts of space. To a lesser extent, microturbines and internal combustion generators will take up space as well. If large numbers of these facilities are installed, some parties suggest that adverse visual impacts may result depending on where these facilities are sited. The siting of distributed generators could also result in adverse noise impacts.

Other disadvantages that could result are: cost shifting or stranded investments as a result of more customers using distributed generation; the impact on the natural gas infrastructure in terms of facilities, supply, and cost; safety problems which could endanger utility personnel and other users; and problems which may affect the safe and reliable operation of the distribution system itself.

C. End-user Side Distributed Generation

Distributed generation facilities can be installed by the end-user as an alternative to taking electric service from the UDC, or they can be installed to provide primary power with the UDC providing backup power, or the end-user can rely on the distribution system for most or all of its needs and use the distributed generation facilities for emergency backup power.

The use of distributed generation on the end-user side of the meter raises the issue as to whether the CPUC should restrict who can be permitted to install, own, and operate those facilities. Should the UDCs be the only ones allowed to do this, or should we prohibit the UDCs and allow all other entities, or should we allow the UDCs and all other entities to participate?

PG&E contends that the installation of distributed generation on the end-user's side of the meter lies outside the Commission's regulatory jurisdiction, and that the CEC only has siting authority for thermal power plants with a generating capacity of 50 MW or more. (See Public Resources Code §§ 25120 and 25500.) However, if the owner of the distributed generation facility uses the UDC for standby service, the Commission has regulatory jurisdiction over the interconnection and the standby service.

The installation of distributed generation on the end-user's side of the meter may be a local government issue. Since distributed generation facilities are usually much smaller than 50 MW of capacity, the CEC may not be involved in the siting aspects of such distributed generation facilities. Although §§ 1003 and 1003.5 require every electrical corporation to submit an application for a certificate authorizing the new construction of any electric plant, line, or extension, an end-user who generates electricity on its own property for its own use or the use of its tenants and not for sale or transmission to others, is not considered an electrical corporation. (Pub. Util. Code § 218(a).) Thus, the CPUC would have no jurisdiction over the siting of distributed generation facilities on the end-user side of the meter.[14]

The issue of whether the CPUC should restrict the UDCs' activities with respect to the installation, ownership and operation of distributed generation facilities that are installed on the end-user side of the meter is intertwined with the issue of what the role of the UDC should be in the distributed generation market. We believe that the role of the UDC, in the context of the deployment of distributed generation, needs to be decided sooner rather than later to facilitate removal of barriers to non-utility participation in the

---

[14] If the owner of the distributed generation facility sells electricity to others, and the sales fall within the exemptions contained in § 218 and § 216(i), the owner of such facility is not considered a regulated electrical corporation.

installation, ownership, and operation of distributed generation facilities on the end-user side of the meter.

Most of the concerns that parties raised regarding end-user distributed generation were safety and reliability related issues.[15] Except for the market power arguments, none of the parties expressed compelling reasons why the regulated UDCs and their unregulated affiliates should not be allowed to participate in customer-side distributed generation.

Today's decision does not prohibit the UDCs from participating in the installation, ownership or operation of distributed generation on the end-user side of the meter. However, this issue will be addressed in the new rulemaking on distributed generation. We will ask parties in that new rulemaking to submit testimony on whether the UDCs and their unregulated affiliates should be permitted to participate in customer-side distributed generation, and what they believe should be the role of the UDC in distributed generation.

Some of the commenting parties have suggested that if distributed generation is placed on the end-user side of the meter, that a valuation system should be employed that assigns value to the owner of the facilities, and for the benefits that it confers on the UDC.[16]

---

[15] Most of the safety and reliability concerns that parties raised will be addressed in the interconnection standards. As for safety issues over the siting of distributed generation facilities, those are issues that the local governmental entities need to address. As discussed later in this decision, the Legislature may want to require uniform safety and reliability standards for all distributed generation installations.

[16] It has been suggested that a value should be assigned if an environmentally friendly technology is used, or if the technology confers other environmental benefits.

Some of the IOUs suggest that a valuation system is not necessary. They contend that the valuation method is similar to what was established for qualifying facilities, and that such a method should be avoided. Instead of establishing a valuation and payment system for perceived benefits, the IOUs believe that the value of such facilities will already be reflected in their price. The IOUs add that the PBR mechanisms provide incentives for pursuing the most cost-effective options.[17]

Southern California Edison Company (SCE) recognizes that the installation of distributed generation may potentially lead to certain cost savings, and that such savings are dependent on many factors, such as location, availability, and operating characteristics. However, SCE contends that further work is needed to develop a methodology to determine the value of the perceived benefits, and crediting them to the appropriate parties. SCE also points out that some distributed generation installations could impose additional costs on the utility, and if so, those additional costs would need to be considered before any credit is provided.

An end-user's decision to install distributed generation is based on economics. If the cost of purchasing, installing, and operating the distributed generator is less than the cost of purchasing the electricity, the end-user is likely to choose the first option. We are not convinced that we should assign a value to this economic choice, and then apportion the value among the involved parties. We do, however, have to be cognizant of the benefits that such facilities may

[17] At the present time SDG&E and SCE have PBR mechanisms in place. (See D.99-05-030 and D.96-09-092.) PG&E filed an application to establish a PBR mechanism in Application 98-11-023. PG&E's application is currently pending before the CPUC.

confer on the distribution system, and ensure that mechanisms are in place that recognize these benefits to the ratepayers and the IOUs.

Parties should be prepared to submit testimony on the concept of the valuation system in the new rulemaking on distributed generation. If a party favors the implementation of a valuation methodology, the party should discuss this in its testimony.

A related concept to the valuation system is net metering. The legislature has defined "net energy metering" in § 2827(b)(3). That subdivision provides as follows:

> " 'Net energy metering' means measuring the difference between the electricity supplied through the electric grid and the electricity generated by an eligible customer-generator and fed back to the electric grid over a 12-month period as described in subdivision (e). Net energy metering shall be accomplished using a single meter capable of registering the flow of electricity in two directions. An additional meter or meters to monitor the flow of electricity in each direction may be installed with the consent of the customer-generator, at the expense of the electric service provider, and the additional metering shall be used only to provide the information necessary to accurately bill or credit the customer-generator pursuant to the provisions of subdivision (e), or to collect solar or wind electric generating system performance information for research purposes. If the existing electrical meter of an eligible customer-generator is not capable of measuring the flow of electricity in two directions, the customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is able to measure electricity flow in two directions. If an additional meter or meters are installed, the net energy metering calculation shall yield a result identical to that of a single meter. An eligible customer-generator who already owns an existing solar or wind turbine electrical generating facility, or a hybrid

system of both, is eligible to receive net energy metering service in accordance with this section."

The Legislature determined in § 2827 that a program to provide net energy metering for "eligible customer-generators"[18] will encourage private investment in renewable energy resources. Every ESP is to develop a standard contract or tariff which provides for net energy metering, and this contract is to be made available to eligible customer-generators on a first-come, first served basis, until the total capacity of the contracts equals 0.1% of the ESP's aggregate customer peak demand.

Several of the commenting parties support the use of net metering for distributed generation facilities. They contend that net metering should be expanded to include other distributed generation technologies besides wind and solar, that the 0.1% limitation should be increased, and that such metering is a fair method of accounting for the power that is supplied to the grid by a distributed generator.

The IOUs contend that net metering can lead to gaming by the eligible customer-generator by taking power from the distribution system when the value of electricity is high, and offsetting that by delivering power to the grid when the value is low.[19] Also, when the customer-generator takes power from

---

[18] An eligible customer-generator is defined in §2827(b)(2) as: "a residential customer, or a small commercial customer as defined in subdivision (h) of Section 331, of an electric service provider, who uses a solar or a wind turbine electrical generating facility, or a hybrid system of both, with a capacity of not more than 10 kilowatts that is located on the customer's premises, is interconnected and operates in parallel with the electric grid, and is intended primarily to offset part or all of the customer's own electrical requirements."

[19] For example, SCE describes net metering as "allowing the customer-generator to deduct the power it delivers to the grid during some time periods from the power it

Footnote continued on next page

the grid, it receives the commodity, as well as transmission and distribution services. However, the customer-generator is only supplying the commodity to the grid. The IOUs suggest that net metering is contrary to the goal of using real time and cost-based pricing, that it subsidizes renewable technologies, and that it allows net metered customers to avoid certain costs that other customers are obligated to pay.[20]

Before the CPUC decides whether or not net metering should be expanded for other technologies, the Legislature may want to weigh in on this issue. At the present time, net metering is only mandated for wind and solar technologies of a certain size, and only benefits a set number of customer-generators. It also appears that net metering can lead to the avoidance of certain costs by the customer-generator, and helps to subsidize particular kinds of technologies.

In our new rulemaking on distributed generation, we will have parties present testimony on whether or not net energy metering should be expanded to include all distributed generation technologies or modified in other ways. None of the supporters of net metering made any detailed proposals in their comments to the OIR. We note, however, that an expansion of net metering seems contrary to the vision of what the competitive generation market should

---

purchases from the grid during other time periods. It assumes that the balance of deliveries and purchases over each accounting period results in net customer purchases, or it allows customers to carry net deliveries in one period forward and assumes they will eventually be offset by purchases in another period." (SCE Reply Comments, pp. 23-24.)

[20] SCE states that it would support an hourly energy credit for distributed generators where the overgeneration would be credited to a customer at the value of the commodity in the hour in which the overgeneration occurred.

look like. If meaningful retail competition is to be achieved, it seems that the same rules should apply to all generating technologies, and subsidies should be eliminated or minimized.

D. Grid Side Applications of Distributed Generation

Grid side applications of distributed generation could consist of small merchant plants that supply energy and capacity, or facilities that support the distribution system.[21] Many of the commenting parties state that grid side installations could be cost-effective alternatives to utility-owned upgrades to the distribution system.

At the present time, the UDCs can install, own and operate distributed generation facilities on the grid for energy system reliability, ancillary services, or as a substitute for upgrading the distribution system.

The issue that arises with respect to on-grid distributed generation is who should be allowed to install, own and operate this equipment. That is, should distributed generation on the grid side be limited to the UDCs only, should it be limited to non-utilities, or should anyone be allowed to participate? Resolving this issue also involves a discussion about what the role of the UDC should be for on-grid distributed generation, and whether there should be an unbundling of distribution related services.

The comments mention two problems with the installation of distributed generation on the grid side by others: safety, and the operation and dispatch of such facilities. SDG&E and SoCalGas stated that the UDCs must have operational control of on-grid distributed generation. They contend that others should not be allowed to control the dispatch of the distributed

[21] The major concern of the EOB is grid side applications of distributed generation.

generation. They argue that UDC control is necessary for safety and reliability reasons, and because they have primary responsibility for the integrity and reliability of the system, as well as the safety of its employees and the public they serve. (See Pub. Util. Code § 330 (f) and (r).)

The operational control argument of the IOUs merits further consideration. In order to maintain the safety and reliability of the distribution system, we will examine to what extent one entity should have control over the operation and dispatch of the distribution system. However, we are not convinced that other parties should be prevented from providing on-grid distribution support services.

The primary issue with a distributed generator on the grid side is dispatch control. QFs are operated according to a standard operating and power purchase agreement. Similar restrictions and contractual arrangements could be put into place for distributed generators supplying distribution support services. Although there is a cost associated with administrative controls and contracts, it allows the development of a competitive market for distribution support services.

Some of the parties contend that the IOUs should be prohibited from owning any distributed generation on the grid side of the meter because Assembly Bill (AB) 1890 (Stats. 1996, ch. 854) and the Preferred Policy Decision sought to remove the IOUs from the generation function. If the IOUs are permitted to own grid-side distributed generation facilities, these parties fear that generation will once again be controlled by the IOUs.

A review of the applicable decisions and statutes suggest that the IOUs are not prevented from owning generation facilities if it is consistent with the public interest, and the ownership does not confer an undue competitive advantage on the IOU. (See Pub. Util. Code § 377.) This suggests that the IOUs may own and operate on-grid distributed generation. However, if the CPUC decides that the unbundling of distribution services will encourage distribution competition, the ownership of on-grid distributed generation by the IOUs may not be appropriate. The CPUC needs to carefully consider what role the UDC should play in the future in deciding whether the IOUs should be permitted to own and operate on-grid distributed generation. The staff study and report should address this issue.

Another argument of parties opposed to IOU ownership of distributed generation on the grid side is that the IOUs can discourage the use of distributed generation by installing on-grid distributed generation, and using standby charges, bypass fees and flexible rate offerings to discourage customers from installing distributed generation on the customer-side of the meter. These are all rate design issues which have some distribution competition aspects to them because distributed generation allows one to bypass the distribution system entirely, and thus can be a competitive alternative to the distribution system. We discuss rate design issues later on in this decision.

We will solicit testimony in the new distributed generation rulemaking on whether or not the UDCs should be prohibited from installing, owning and operating distributed generation on the grid side of the meter. We will also solicit testimony on whether the UDCs and their unregulated affiliates should be permitted to participate in this market, and what they believe the role of the UDC should be in distributed generation.

The concerns regarding a valuation system for distributed generation also applies to grid-side applications. As discussed above, we do not believe a valuation system should be applied to grid-side distributed generation facilities. We favor a market competition approach. If there is a need for distribution support services, there are likely to be entities who are willing to provide the service for a certain price. Such an approach eliminates the need for determining what offsets each involved party should receive. Furthermore, sufficient incentives could be created in their PBR mechanisms, to allow the IOUs to install the most cost-effective options.

E. Interconnection Issues

The existing interconnection rules for the three largest electrical corporations in California are found in Rule 21 of their respective tariffs.[22] These tariff provisions specify the design and operating characteristics that each generator, including a QF, must meet in order to be interconnected, the type of interconnection facilities that are required, and the entity that bears the cost of such facilities. No one suggested in their comments that the existing interconnection tariffs will facilitate the deployment of distributed generation. Indeed, most of the commenting parties seem to recognize that some changes to the existing tariffs are needed to develop uniform interconnection standards between third-party generators and the UDC.

The interconnection of DER to the UDC's distribution system raises numerous safety, technical, and administrative issues. Most of the commenting parties recognize the need for reasonable interconnection standards that protect utility workers and the public, and standards that will not negatively impact the reliability and the integrity of the electric distribution system. Many of the parties also recognize that the adoption of appropriate interconnection standards can address these concerns.

---

[22] Rules 1 and 2 also are of aid in understanding Rule 21. Rule 1 defines the expressions and terms used in the tariff schedules. Rule 2 , among other things, describes the types of electric service that are available, the specifications regarding voltage, frequency, and phase, and a description of the protective devices.

Some parties also see a need to eliminate interconnection rules that they consider both unnecessarily burdensome and expensive and time consuming to implement. These rules are viewed as artificial barriers which prevent the interconnection of distributed generation facilities to the electric grid, and make it uneconomic for an end-use customer to employ distributed generation facilities.

Other parties commented that there is a lack of consistency in the interconnection requirements from one utility to another. They contend that this lack of consistency can impair the ability of DER manufacturers to produce uniform equipment and thus realize the benefits of economies of scale resulting from standardized production.

We believe that the time is ripe for interested participants to discuss and develop new interconnection standards that reflect the availability of new technologies and an increasingly competitive environment. The comments by the various parties provide us with certain principles in designing new interconnection standards. First, the interconnection standards need to ensure that the distribution system remains safe and reliable. The Legislature specifically recognized safety and reliability concerns in § 330 (f), (i), and (r).[23] Second, the interconnection requirements need to be applied in a non-discriminatory manner so that the interconnection requirements are not subject to the discretion of the UDCs. And third, the interconnection requirements must

---

[23] In deciding what level of safety protection is necessary, we realize that this is likely to have an impact on the engineering complexity and cost of the distributed generation equipment. This, in turn, may adversely affect the economic advantage that a customer might realize from deploying distributed generation.

be technology neutral so that the interconnection standards do not favor one technology over another.

There are a variety of different interconnection issues that need to be addressed by the parties. We agree with the suggestion of many of the parties that a workshop process is the most appropriate method to address these technical interconnection issues. In the new rulemaking on distributed generation, we will set up a workshop process to address the interconnection issues, and other related issues.

In addition to the proposal for the 20 MW limitation for distributed generation, we provide a list of some of the other interconnection issues that we believe need to be addressed during the workshop process.

First, regarding safety, there is a need to ensure that adequate protective devices are in place so that distributed generation facilities cannot backfeed power to the distribution grid when the grid is out of service due to maintenance, outages, or other causes. This raises the issue as to whether all of the facilities connected to the distribution system must have a UDC-accessible disconnect switch. Another related safety issue is whether the owner of a distributed generation facility that is not connected to the distribution system should have to notify the UDC or some other entity of such an installation. In addition, the workshop process should address whether the interconnection standards need to be developed for distributed generators only, or does it need to address all DER.

Second, many parties have recommended the need for interim statewide interconnection standards, pending the development of national standards. National standards will give the DER manufacturers some assurances that they can economically manufacture equipment, and readily install it in all of the different states. The Institute of Electrical and Electronics Engineers (IEEE), with the input of interested parties, is developing a set of nationwide interconnection standards. This national standard is expected to be completed around December 2001. Although uniform statewide and national standards are desirable, it also appears that there are UDC-specific conditions which may affect the interconnection standards. The workshop participants should discuss and explore how these local conditions can be accommodated in any interim and permanent statewide standards that are ultimately adopted.

We believe that there is a need to develop statewide interim interconnection standards as soon as possible. Pending development of national standards, interim statewide standards are needed so that the deployment of distributed generation facilities can be facilitated as quickly as possible. If we wait for the IEEE to develop nationwide standards, the existing interconnection tariffs may act as barriers to the development of distributed generation.

Third, the workshop process should address whether "type testing" of DER equipment can be incorporated into the interconnection standards and process, or whether type testing cannot or should not be done. Type testing allows a manufacturer to seek an approval from a recognized entity that the equipment it produces meets certain interconnection standards. If type testing is permitted, that has the potential to facilitate greater deployment of DER throughout the state and the nation. If type testing is to be permitted, we need to develop procedures on the testing standards, as well as what type of entity should certify whether the equipment meets the adopted interconnection standards.

A fourth interconnection issue to address is whether the owner of the DER can select the interconnection voltage level. The parties advocating such a choice contend that some owners may find that a primary distribution or transmission level interconnection is best, and that the choice of interconnection may be influenced by whether a distributed generator is able to sell excess capacity or if it can provide distribution support services, i.e., ancillary distribution services.

Fifth, the parties should discuss whether utility personnel, air quality districts, and building inspectors from local governments, should receive training regarding the deployment of distributed generation, and the impact that distributed generation may have on them. For example, PG&E states that the use of distributed generation by a smaller customer may require the development of new building codes, installation oversight, and consumer protection programs for a product that previously enjoyed largely industrial applications.

And sixth, the workshop process should identify what changes are needed to the existing tariffs, including eliminating QF distinctions, that prevent a distributed generation facility from interconnecting. SCE acknowledges that its current tariff prohibits a non-QF generator from operating in parallel with SCE's system and taking standby service. SCE contends that this restriction exists because its current volumetric rate design does not allow SCE to fully recover its T&D costs for customers who self generate. SCE states that it intends to revise its rate design later this year, and to remove this restriction. SCE asserts that immediate action to remove this restriction would result in cost shifting because the current tariffs for some customer classes do not fairly recover the costs the utility incurs to provide standby service. Such a distinction should be eliminated at the earliest opportunity, whether that occurs when interim interconnection standards are adopted in the new distributed generation rulemaking, or in SCE's rate design proceeding.

F. Operational and System Planning Issues

1. UDC Operational Issues

At the present time, the UDCs are responsible for the planning, maintenance and operation of their distribution systems. Distributed generation will impact the maintenance and operation of the distribution system. The parties' comments about the operational issues concerning the distribution system center around the following five major areas of concern: safety, reliability, dispatch, scheduling, and communications.

The system's operational issues will ultimately depend on the future role of the UDC. However, as discussed in the distribution competition section of this decision, the ownership and operation of the distribution system will remain unchanged in the short term. Therefore, we will discuss the system operational issues from the point of view that the UDCs will continue to own, operate, and maintain their distribution systems.

As noted in earlier sections, one of the most important issues is the effect of distributed generation on the safety of workers and the public, as well as on the reliability of the distribution system itself. The comments also express a concern as to whether the addition of distributed generation facilities will delay the restoration of the distribution system following a major outage. Also, some of the parties expressed concern about whether voltage control and reactive power will be compromised, and whether substation facilities will be adequately protected.

Islanding of distributed generation facilities is also a safety concern. EPRI describes islanding as a situation where the distributed generation facility and a portion of the distribution system operate separately from the rest of the distribution system following an outage. Utility crews working on a section of line they believe is deenergized can be injured or killed if an islanding condition occurs. Also, once a portion of the distribution system becomes separated from the main system, the utility no longer controls the frequency or voltage in the isolated section, which may damage equipment on that portion of the distribution system.

The safety and islanding issues appear to be concerns which can be readily resolved through the use of interconnection standards, and by requiring certain kinds of protective devices to ensure the safety of the public and utility workers, and the facilities of both the UDCs and of the distributed generators. Thought should also be given as to whether mandatory mapping and marking standards should be followed for the installation of distributed generation facilities.

The workshop on interconnection should discuss whether the operators or owners of islanded distributed generation should be required to notify the UDC or other entity of such installations.[24] Safety concerns and exit fee considerations may justify the need for such notification. Legislation may be needed to require this of owners and operators of such equipment.

Some parties are concerned that the reliability of the T&D system may be affected due to the use of DER. But none of them asserted that the interconnection standards will be unable to adequately address this issue. We are confident that the interconnection workshop will be able to adequately address the reliability concerns of the parties.

---

[24] The use of small portable generators that are used for power outages, or for locations without electric service, may provide some useful comparisons as to why such a notification process may or may not be needed.

The parties have also raised the issue of who should be responsible for the dispatch of distributed generation if distributed generators are permitted to sell their excess capacity or provide ancillary services to the market. This dispatch issue depends on the future role of the UDC.[25]

If it is decided that the UDCs should not be allowed to own or operate distributed generation facilities, the UDC could still operate the distribution system. Section 330(r) provides that the ownership and maintenance of the distribution system are to be provided over facilities owned and maintained by the electrical corporations. Thus, the dispatch responsibility is to remain with the regulated electrical corporation. Protocols will need to be established, however, to govern the dispatch of the distributed generation facilities.

Dispatch of distributed generation facilities may be an issue if it is decided that the UDCs and other entities are allowed to provide on-grid distributed generation. The issue could arise when the UDC needs to dispatch facilities, and the UDC has the choice of dispatching a UDC-owned facility or one that is owned by a non-UDC. Dispatch may also be an issue with the kind of DER that is dispatched. Due to different technological attributes, some DER facilities may be more readily dispatched than others. This could lead to a preference for dispatching a particular facility over another.

The workshop process should develop recommendations for dispatch, with a focus on what type of hardware should be required. Should

---

[25] For example, if an Independent Distribution Operator (IDO) is authorized in the future, an entity other than the UDCs would be responsible for the dispatch of distributed generation facilities. The IDO concept is discussed later in this decision.

parties believe that there are market power concerns associated with dispatch, parties should address these potential problems and recommend solutions as part of their testimony on whether the UDCs should be permitted to own and operate on-grid and end-user side distributed generation.

Scheduling issues will depend on whether the non-utilities will be allowed to sell excess capacity or ancillary services. If they are allowed to do so, then appropriate protocols will need to be developed. Depending upon where the electricity is needed, the involvement of the UDC, the Power Exchange, and the ISO may be needed. Parties interested in the scheduling issues should discuss in their testimony in the new rulemaking what kind of scheduling protocols will need to be developed if the non-utilities are allowed to use their DER facilities to sell excess capacity or to provide ancillary services.

Some parties commented that in order to have efficient and effective dispatch and control of distributed generation, advanced communications and metering will be needed. A few of the parties suggested that the interconnection standards should include communications and metering issues.

We agree that communications and metering need to be addressed in the new rulemaking on distributed generation. The communications and metering issues do not appear to be insurmountable obstacles. QFs interfacing with UDCs use similar protocols, and can provide a useful starting point for developing communications and metering requirements. The workshop process is the most appropriate place to address these kinds of issues.

Another issue raised by the parties is who should have jurisdiction over the safety of the distribution system and the distributed generation facilities on the end-user side of the meter. In accordance with subdivisions (f) and (r) of Section 330, the distribution system is to be owned and maintained by electrical corporations that are subject to the CPUC's regulation. Thus, the CPUC retains jurisdiction over the distribution system. Distributed generation facilities that are interconnected to the distribution system must meet the interconnection tariffs that have been approved by the CPUC.

As for the safety of the electrical systems of the publicly owned utilities, the CPUC has jurisdiction. (See D.98-03-036, pp. 8-10; D.98-10-059, pp. 2-3.) If the publicly owned entities or their customers interconnect to a UDC's distribution system, the UDC's interconnection tariffs would apply.

2. UDC System Planning Issues

Distributed generation on the end-user side and on the grid side of the meter could have significant impacts on distribution system planning, and the construction of additional distribution facilities. PG&E states that if the distribution planning process does not keep track of the growth in the use of distributed generation, it may result in overinvestment or underinvestment of distribution facilities some areas.

Since end-user side distributed generation applications will be an economic decision by end-users, the UDCs may have little advance notice that a customer will switch to distributed generation for some or all of the customer's needs. As a result, system planning may not be able to adequately consider the impact.

On-grid distributed generation is likely to have less of an impact on system planning because the level of use and deployment is known to the UDCs. Nevertheless, in order to decide whether on-grid distributed generation should be deployed, the UDC needs to determine when such resources are needed for system support. If non-UDCs are allowed to provide on-grid distribution support, the CPUC and the parties may need to develop procedures for: informing interested entities of the need; what the selection process will be; what the specifications will be; and what type of contracts, and operational and dispatch rules will be needed. A possible alternative to this process, if the UDCs are excluded from participation, is to leave it up to the UDCs to develop the notice and award procedures, and for the UDCs to make a cost effective selection using the PBR incentives.

System planning raises the question of who should be responsible for system planning, and the future role of the UDC. Since § 330 requires that the distribution system continue to be owned and maintained by the "state's electrical corporations," and regulated by the CPUC, the responsibility for distribution system planning should remain with the electrical corporations regulated by the CPUC.

In order to minimize distribution costs, while having sufficient distribution facilities to meet the needs of end-users, the UDCs' forecast of distribution system needs should account for the expected growth in DER. The UDCs, end-use customers, and other interested parties need to consider how the future deployment of DER can be effectively integrated with distribution system planning. This issue is better suited for a workshop rather than testimony. Therefore, in the new distributed generation rulemaking, we direct the Energy Division to hold a workshop to facilitate discussion of how the UDCs can identify the level of deployment of DER, and to incorporate that into its distribution system planning process for future distribution system improvements and upgrades.[26]

The United States Fuel Cell Council (USFCC) suggested that distribution company integrated resource planning (DIRP) should be used in conjunction with a performance-based ratemaking (PBR) mechanism to minimize costs. The DIRP method is based on the concept and principle of integrated resource planning and includes: measures to ensure the cost-effective substitution of energy efficiency, modular generation, and energy storage for T&D upgrades; providing incentives for more efficient design and operation of the T&D system, including how infrastructure is added for customer growth; inclusion of the cost of line losses in evaluating T&D delivered performance; and least cost planning, including the incorporation of the cost of environmental effects of energy production in the UDC's evaluation.

The Edison Electric Institute (EEI) contends that the DIRP approach should be rejected because it substitutes administrative choices for market-based solutions. EEI points out that in AB 1890, the Legislature sought to rely on the market to allocate generating resources.

In some respects, the DIRP method appears similar to the valuation method that others have suggested, about which we express some reservations. At the same time, we recognize that as more end-users install distributed generation, close coordination with distribution system planning will be needed. In the new rulemaking on distributed generation, testimony should address how system planning issues can be coupled with other incentive

---

[26] We recognize that this may also impact the factors and incentives which went into the development of the PBR mechanisms.

mechanisms to provide cost effective distribution service that can meet future needs, while ensuring safety and reliability.

3. Independent System Operator Operational and System Planning Issues

Although the ISO's planning process and system operations were not the subject of any questions posed in this OIR, distributed generation is likely to have some impact on transmission system planning and operations. We have coordinated with the EOB to identify these possible impacts.

If distribution level generators participate in the bulk market and ancillary services, those generating facilities are likely to impact the operation of the ISO because the ISO has jurisdiction over the dispatch of all scheduled or bid energy and ancillary services on the ISO controlled grid.[27] However, in order for distribution level generators to participate in the bulk energy and ancillary services markets, the distributed generators will need to interconnect with the ISO controlled grid through the UDC's wholesale distribution access tariff. In order to transmit energy and ancillary services out of, or through, the ISO controlled grid, a distribution level generator will also need the services of a scheduling coordinator that has been certified by the ISO.

The EOB believes that due to the relatively small size of the distributed generation facilities, distributed generation will probably not be a factor in the ISO's transmission system planning until it is deployed in significant quantities at the distribution level. Although the ISO's long-term grid planning

---

[27] The ISO controlled grid is the system of transmission lines and associated facilities of the participating transmission owners that have been placed under the ISO's operational control.

process is still under development, such a process will take into account any significant or predictable growth in distribution level generation.[28]

G. Sale of Excess Electricity Capacity

As a result of AB 1890 and the CPUC's Preferred Policy Decision, the market for electricity generation was opened to competition in California. Many of the end-users who install distributed generation will do so to serve their own electrical needs. However, some may find the ownership of a distributed generation facility to be more cost effective if they can also sell their excess capacity to others on the distribution grid, or to the transmission grid.

In order for distributed generators to sell their excess capacity to other end-users on the distribution system or on the transmission system, they will need access to the distribution system. Section 330(k) states in part that in order to achieve meaningful wholesale and retail competition in the electric generation market, it is essential to:

> "(3) Provide customers and suppliers with open, nondiscriminatory, and comparable access to transmission and distribution services."

Distribution grid access raises several issues.

The first issue is whether the UDCs should be required to provide an unbundled distribution-only service, i.e., distribution wheeling service that the distributed generator can use to transport electricity to other loads that are

---

[28] All interested parties, including the UDCs, can participate in this long-term grid planning process. There are several active forums where this planning process is being considered, such as the San Francisco Peninsula Area Transmission Study Group, and the ISO Longterm Grid Planning Working Group. Parties who are interested in these issues should contact the Independent System Operator for information about how they can participate.

supplied by the same substation without the end-user incurring any transmission charges.[29] At the present time, if a generator wants to wheel its power to a customer located on the same distribution circuit, the customer who wants the electricity from the generator is obligated to pay transmission and distribution charges. Some of the parties contend that this acts as a disincentive to connect distributed generation at the local distribution level. These parties recommend that the transmission charges be unbundled from the distribution charges, thus reflecting the true cost of distribution wheeling.[30]

PG&E and SCE oppose the implementation of a distribution-only service. They contend that distribution wheeling would allow a customer to avoid paying its fair share of the costs of constructing, operating, and maintaining the ISO-controlled transmission grid, including the procurement of ancillary services which support the operation of the distribution system and the reliability of the distribution level service. In addition, if a distribution-only rate is permitted, it would result in a shifting of all of fixed costs to other customers.

PG&E and SCE also note that a similar proposal for a distribution-only service is currently pending before the Federal Energy Regulatory Commission (FERC) in Docket ER 97-2358. The California ISO opposed the establishment of a wholesale distribution-only service. PG&E and

[29] SCE describes distribution-only service as service from a generation unit on a distribution system to a load on the distribution system, which for purposes of charges, is treated as divorced from the ISO-controlled grid.

[30] ORA proposes that distribution services be unbundled by voltage level. ORA contends that such unbundling would allow generators who connect at distribution voltages to serve downstream load, and be credited for not wheeling through higher voltage T&D facilities.

SCE cite the following statement made by the ISO in that proceeding as to why a distribution-only service should not be permitted:

> "Even if the path from the resource to the load does not involve the transmission system, transactions on the Companies' distribution systems directly implicate these responsibilities of the ISO because the distribution systems are connected to the ISO Grid. If generation or load increase or decreases on the distribution system, the effects are felt on the ISO Controlled Grid."

It is premature to make a decision today about the proposal for a distribution-only service. Since the proposal for the distribution-only service could be an economic factor that end-users might consider before deciding whether to purchase their electricity needs from a distributed generator in a direct access transaction, we shall consider it in the new rulemaking on distributed generation. Parties are invited to submit testimony on the proposal in that rulemaking.[31]

The second issue that distribution access raises is whether an entity that sells a distributed generator's excess capacity is considered a public utility under the existing statutes. It is not clear from reading the applicable Public Utilities Code sections whether a distributed generator, which uses cogeneration technology or a non-conventional power source, would be exempt from the CPUC's regulation as a public utility.

A "public utility" is defined in § 216(a) to include every electrical corporation that performs a service for, or delivers the commodity to, the

[31] If the distribution only service is allowed, the CPUC would then need to address the rate design for that service.

public.[32] If the electrical corporation performs that service for, or delivers the commodity to, the public for compensation or payment, it is considered a public utility subject to the jurisdiction, control and regulation of the CPUC. (Pub. Util. Code § 216(b).) However, § 216(i) provides:

> "The ownership, control, operation, or management of an electric plant[33] used for direct transactions or participation directly or indirectly in direct transactions, as permitted by subdivision (b) of Section 365, sales into the Power Exchange referred to in Section 365, or the use or sale as permitted under subdivisions (b) to (d), inclusive, of Section 218, shall not make a corporation or person a public utility within the meaning of this section solely because of that ownership, participation, or sale."

Thus, based on § 216(i), it appears that if a distributed generator sold its electricity in a direct access transaction, either directly or indirectly, or if it sold its power to the Power Exchange, or if it was a cogenerator or it produced power from a non-conventional power source, and it sold electricity for the purposes set forth in §218(b), it would not be considered a public utility.

The third issue raised by the sale of excess capacity over the distribution system is whether the FERC or the CPUC will have jurisdiction over the transaction. As some of the parties pointed out, the FERC has held that it has exclusive jurisdiction over the rates, terms and conditions of the interconnection when distribution facilities are used to serve wholesale customers, i.e., there is movement of electricity over the distribution system for delivery to a seller for resale. PG&E also suggests that "interconnection arrangements for generation

---

32 An "electrical corporation" is described in § 218.

33 The term "electric plant" is described in § 217.

selling through the PX, to wholesale customers, or to retail customers through direct access transactions, may all be subject to FERC jurisdiction." (PG&E Reply Comments, pp. 34-35.)

We look to FERC Order No. 888 in reviewing PG&E's argument. When a distributed generator wheels electricity over the distribution system to a retail direct access customer, FERC Order No. 888[34] seems to suggest that the state retains jurisdiction. FERC noted in that order:

> "The Federal Power Act recognizes that retail marketing areas are governed by state law. Moreover, we believe that states have authority over the service of delivering electric energy to end-users. ... State regulation of most power production and virtually all distribution and consumption of electric energy is clearly distinguishable from this Commission's [FERC] responsibility to ensure open and non-discriminatory interstate transmission service. Nothing adopted by the Commission today, including its interpretation of its authority over retail transmission or how the separate distribution and transmission functions and assets are discerned when retail service is unbundled, is inconsistent with traditional state regulatory authority in this area."

This issue of jurisdiction over the rates, terms, and conditions of the interconnection between the distributed generator and the UDC, for the purpose of serving a direct access customer of the distributed generator, is an issue that a party is likely to raise in the near future. Interested parties should comment on this issue when they submit their testimony on the distribution-only proposal.

---

[34] FERC Order No. 888 can be found in "FERC Statutes and Regulations, Regulations Preamble, January 1991-June 1996 ¶ 31,036.

Another issue related to the sale of excess capacity is locational market power. Depending on where distributed generation is sited, a generator may be able to raise market prices for energy or ancillary services above the competitive market levels when there is inadequate transmission grid capacity during peak load periods. This has resulted in the expenditure of much time and resources to develop contracts describing the terms, conditions, and rates under which certain plants can operate as "reliability must run" plants.

Since distributed generation can be used to alleviate grid congestion, it has locational market power implications. If distributed generation units sell power to adjacent customers during times of congestion, a higher than normal price can be sought. The new rulemaking on distributed generation will need to examine how distributed generation affects locational market power, whether there are concerns that need to be alleviated, and how to deal with the potential problems of interfacing with ISO processes. Coordination with the ISO and its market development group may be needed in this regard.

H. Rate Design Issues

The installation of distributed generation raises several rate design issues. If the distributed generator uses the distribution system as backup supply, then standby charges may apply. If the distributed generator relies on its facility to serve all of its need, i.e., islanding, then bypass of the distribution system becomes an issue. Bypass, together with standby charges, also affect the amount of potential stranded costs. The outcome of any rate design proceeding needs to recognize the interrelationship of these issues.

The rationale for the standby charge is that it supports the UDC's recovery of the costs associated with the reservation of capacity, and the procurement and delivery of electricity to a standby customer who may need backup electric service.[35]

Some of the parties contend that the standby charge should be based on the incremental cost of providing service, while others believe that it should be based on the full costs of actually serving the customer. If the standby charge is to reflect the cost of service, one suggestion is to develop performance data on the reliability of the installed distributed generation facilities. Such data could then be used to assess how often the UDC's standby service may be needed. One of the parties also commented that if the standby charge is based on actual usage only, other distribution customers might end up subsidizing those standby service customers who never need backup power from the distribution system. Several of the parties point out that if the utility fails to recover all of the costs of serving a departing customer, those costs may be unfairly shifted to the other distribution system customers who are least able to leave the distribution system.

SCE suggests that an essential component of open and nondiscriminatory access is tariffs that fairly reflect the cost to serve the customer. According to SCE, current standby charges reflect only the cost of the T&D facilities necessary to serve a customer's backup requirements on demand. In order to determine the total costs for such services, SCE suggests that studies be performed to quantify the costs associated with providing standby service. SCE states that the standby charge should include the cost of facilities available to serve customers in the event of an outage of the distributed generation facility,

---

[35] The EEI describes "standby" service as any number of discrete generation services that are not normally used by customers, but which are available through interconnection with the utility. "Backup" service usually refers to energy or capacity supplied during unscheduled outages on on-site generating equipment.

including the costs of any special facilities that need to be installed to accommodate specific interconnection requests, as well as the cost of any imbalance energy imposed on the utility to serve the standby customer's backup energy requirements.

The CPUC needs to design standby rates which facilitate the deployment of customer-side distributed generation, while ensuring that they reflect the fair and reasonable costs of providing standby service by the UDC. The standby rate needs to send the proper price signal to a prospective purchaser of distributed generation so that the end-user has sufficient information to make a rational economic choice. In considering the proper rate design, the CPUC also needs to keep in mind that high standby charges can reduce the cost-effectiveness of distributed generation, which could lead the end-user to bypass the distribution system altogether. If the standby charges do not recover the full costs associated with maintaining distribution service to distributed generation that is connected to the grid, this may have an adverse impact on the remaining UDC customers. The CPUC should also endeavor to ensure that there is consistency in the design of standby rates for all of the IOUs in California. All of these considerations must be carefully balanced by the CPUC in the design of the standby charges.

Some possible rate design options include: standby charges that reflect different levels of reliability, for example, firm standby or non-firm service; or standby charges that reflect the frequency of use, such as a low reservation charge and a high usage charge; or a fixed connection charge, as opposed to the current charge based on capacity and energy; or standby charges based on a time of use rate structure; or a standby charge that differentiates between planned outages and unscheduled outages; or allowing the UDCs to establish contracts with customers that would require the customer to give an extended notice before the customer could depart the distribution system.

In the new rulemaking on distributed generation, there will be an opportunity for interested parties to submit testimony on the various rate design issues that confront us. Parties should provide testimony on whether standby charges are appropriate, and, if so, how the standby charge should be structured.

If more customers elect to disconnect from UDC service entirely, the remaining UDC customers will bear a greater burden of the costs of operating the T&D system unless some sort of bypass charge is imposed on the departing customers, or some other allocation of costs is developed. PG&E has requested authorization to charge bypass fees in Phase 2 of its general rate case, Application (A.) 99-03-014. The bypass charge is also referred to as an exit fee. The rationale for imposing the charge is that it allows the UDC to recover some or all of the perceived stranded costs of the facilities that were used to serve the departing customer.

Some of the parties contend that a bypass fee should not be authorized by the CPUC because it acts as a barrier to competition by biasing the customer to stay with the UDC rather than to use distributed generation. They contend that the imposition of such a fee may make the installation and ownership of distributed generation an uneconomic choice. The Office of Ratepayer Advocates (ORA) states that bypass is a natural consequence of the technology changes taking place in generation, and that such a charge should not be imposed. ORA also states that exit fees for self generation would be difficult to collect, and could lead to creative means to close an account and thereby avoid the exit fee.

We recognize that bypass charges may be an issue in other CPUC proceedings. In each proceeding, the parties should alert the presiding officer that the potential for overlap exists. The presiding officers in each proceeding will then coordinate to decide where bypass charge issues are properly addressed.[36] In the interim, parties are invited to submit testimony on the broad policy considerations surrounding bypass charges in the new rulemaking on distributed generation.

ORA states that other options should be considered besides the imposition of an exit fee to allow a UDC to remain competitive. For instance, a flexible PBR mechanism and distribution service unbundling could be explored to offer distributed generators more options while encouraging them to remain connected to the grid.

The UDCs and some of the other parties have suggested that a PBR mechanism be used in conjunction with distributed generation to make improvements to the distribution system while minimizing costs. Other parties stated that the CPUC needs to ensure that the costs associated with the distribution system are not shifted to those customers who cannot afford to install distributed generation facilities. One suggestion is to establish a PBR mechanism that separates the linkage between UDC revenues and electric throughput. For example, if electrical load is reduced due to the use of distributed generation, the IOUs could be rewarded for deferring or avoiding improvements and upgrades to the distribution system.

Other parties suggested that the linkage between the UDC's sale of electricity should be decoupled from the utility's profit. For example, the

---

[36] As stated in the June 9, 1999 scoping memo and ruling in A.99-03-014, PG&E's proposed wires bypass charge will be addressed in that proceeding. However, as that ruling noted, the review of the bypass charge in that proceeding does not preclude its consideration in a broader policy context in this OIR.

reduced load due to distributed generation would not adversely affect the UDC's earnings, if the UDC was rewarded for avoided or deferred wire investments and reliability improvements. If less reliance is placed on sales volume, the UDCs may be more receptive to the deployment of distributed generation.

The rate design issues associated with distributed generation have a symbiotic relationship to each other, and to stranded costs. What we decide on standby and bypass charges affects the validity of stranded costs. In their testimony on rate design in the new distributed generation rulemaking, parties should discuss the interrelationships between the standby charge, bypass charge, and recovery of stranded costs. The parties should propose a consistent approach to address all of these issues. The parties should also consider how the PBR mechanisms or other proposals can be used in conjunction with rate design, so as to minimize the costs to consumers while allowing the UDCs to fairly recover their distribution system costs.

Some parties also commented that if distributed generation leads to bypass of the UDC's distribution system, that funding for the public purpose programs identified in § 381 may be reduced. This issue is addressed in the "Public Purpose Programs" section of this decision.

I. Stranded Costs

Some parties warn that as the deployment of distributed generation grows, more customers will rely less on, or leave, the distribution system. Those parties contend that the loss of customers and the associated revenues will result in stranded investment costs, and the remaining distribution system customers will bear the costs of these unused or underutilized distribution system facilities.

Other parties suggest that no stranded costs will result. Instead, the unused or underutilized assets could be used to meet new loads. ORA points out that stranded costs may result from conditions other than the use of distributed generation. For example, the distribution grid may be underutilized because the projected load growth that the distribution system was sized for, did not materialize.

The parties' comments are mixed with respect to whether the deployment of distributed generation will result in significant bypass of the distribution system. Some of the parties believe that there will not be a large scale departure from the distribution system. Instead, those end-users who take advantage of distributed generation are likely to continue to rely on the distribution system for certain services.[37] In addition, some of the parties believe that load growth will exceed any load loss that may occur.

Some of the parties suggest that in order to determine whether stranded costs exist, a methodology needs to be developed to assess whether stranded costs really exist. They contend that the assessment should include the benefits of distributed generation, as well as the revenues generated as a result of the deployment of distributed generation.

In our new rulemaking on distributed generation, we will solicit testimony on how to assess whether stranded costs have occurred, how stranded costs can be identified, and what, if any, benefits and revenues should be considered as offsets.

---

[37] SDG&E states in its reply comments that if all of the customers who install distributed generation on their side of the meter remain connected to the grid for standby service, that this continuing interconnection makes stranded distribution assets a moot point.

J. California Environmental Quality Act

The Coalition of California Utility Employees (CCUE) contends that any CPUC decision which encourages the deployment of fossil fueled distributed generation facilities, is subject to the California Environmental Quality Act (CEQA).

In order to determine whether the provisions of CEQA apply, one must determine whether the contemplated activity is a "project" as defined by Public Resources Code § 21065. That code section provides as follows:

" 'Project' means an activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and which is any of the following:

> (a) An activity directly undertaken by any public agency.
>
> (b) An activity undertaken by a person which is supported, in whole or in part, through contracts, grants, subsidies, loans, or other forms of assistance from one or more public agencies.
>
> (c) An activity that involves the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies."

At the present time, the CPUC is only in the process of gathering information about distributed generation. This OIR, and today's decision, have not taken or adopted any steps which makes it easier to deploy distributed generation facilities. Instead, this decision merely paves the way for a detailed examination of distributed generation. Since there is no "project" before us at the present time, the CEQA requirements do not apply to the present OIR. It will be in the new rulemaking on distributed generation that the CPUC will decide how the regulatory framework will be changed to facilitate the deployment of such facilities. We will direct the Legal Division and the Energy Division to determine whether the new rulemaking into distributed generation will require a more extensive CEQA review.

K. Local Government Impacts

In this OIR, we recognized that the deployment of distributed generation could have an impact on other state agencies, such as the California Air Resources Board (CARB), as well as on local governmental entities.

The placement of distributed generation facilities may have air quality impacts. Some distributed generation facilities may be of a size that triggers the compliance requirements of certain air quality districts. Smaller distributed generation facilities may not trigger these compliance requirements by themselves, although the cumulative impact of numerous installations of small distributed generation facilities could have an adverse impact on air quality. The CARB and the local air quality districts should be aware of these possible impacts, and may want to reexamine their standards in light of the deployment of such facilities.

As for the comments regarding the availability and use of emission credits, resolution of those issues should be left to the appropriate government agencies.

As described earlier, the siting of distributed generation facilities may also involve land use and zoning, as well as building permit and code issues. Of particular importance is the distributed generator's compliance with all applicable electrical codes. If the electrical codes of local jurisdictions do not address equipment capable of producing large amounts of electricity, those jurisdictions will need to be made aware of this issue.

Local governments may see numerous proposals to install the same or similar types of distributed generation equipment. If the equipment has no environmental impacts at all, the Legislature may want to consider exempting certain distributed generation types from CEQA. Other strategies to facilitate CEQA review of the siting of distributed generation technologies by local governments may also be a subject of interest to the parties. We will ask that the CEC hold a workshop in the new rulemaking to discuss whether the siting of distributed generation can possibly qualify for some form of streamlined CEQA review at the local government level.

This decision does not propose anything that would interfere with the authority over the siting and operation of any distributed generation or DER facilities by other state agencies and local governments.

VII. Competition In Distribution Services

A. Distribution Competition in General

When we opened this OIR, we observed that distributed generation could replace or reduce the demand for electricity from the UDCs, and that this reduction in demand could have implications for the existing transmission and distribution system. Although we did not define distribution competition in the OIR, we identified four possible forms of distribution competition: end-user owned distributed generation; electrical service provided by irrigation or municipal districts, or by other publicly owned utilities; privately owned electric generation and distribution providers; and master metering and submetering in residential and commercial developments. In question 4 of the OIR, we asked the parties to provide examples of how competition was developing with respect to distribution facilities and services.

The comments provided a wide range of thoughts about the various forms of distribution competition. The IOUs suggest that distribution competition was not defined by the other parties, but it appeared to be an amorphous concept that has different meanings for different stakeholders. Some of the IOUs believe that distribution competition is nothing more than relitigating issues that have already been decided, seeking to unbundle distribution services, and seeking to redefine the UDC's role in an unbundled environment.

SCE described the other parties' views on distribution competition as follows: a customer being allowed to take distribution service at a higher voltage level; allowing an end-user to own substations and other distribution facilities; spot municipalization, i.e., the formation of a new municipal electric utility to provide service to a previously undeveloped piece of land located within the IOU's service territory; addition of customers by irrigation districts; aggregating loads; master metering; opportunities for meter service providers; the dismantling of the IOUs to nothing but a wires only company; or leaving the IOUs to deal only with the management of the distribution right of way.

ORA defines distribution competition "as the right and practical opportunity for customers to have open access to quality electric distribution products and services and to exercise meaningful choices." (ORA, Reply Comments, p. 1.) ORA states that distribution competition can take on many forms such as: the right to self provide or purchase distribution systems; the right to forego selected distribution services without undue penalty; competition for the right to operate a portion of the T&D system; the ability of local government to choose from among a variety of providers; the ability of consumers or local governments to change distribution service providers at a reasonable frequency; or allowing anyone to build and own any distribution upgrades or distribution facilities for new developments.

In the joint comments of the Energy Producers and Users Coalition (EPUC) and the Cogeneration Association of California (CAC), they state that distribution competition is not new, and that competition has been provided by irrigation districts, and by cogenerators. EPUC/CAC does not view the issue as one of allowing competition to take place, instead, it is whether competition should be broadened.

Many of the parties favor opening up the various distribution services to competition because they believe that the existing distribution costs substantially exceed the cost of electricity. Since the T&D charges make up a substantial part of the bundled electricity service bill, the proponents of competition assert that it is advantageous to seek out alternatives to the existing distribution system.

We believe that the record is not sufficient at this point to frame a proceeding on the broader issues regarding distribution competition. Instead, further study and information gathering about these issues, and the impacts upon various customer classes, are necessary. Various parties offer different definitions of "distribution competition" and there is no consensus on what it is or its scope. Some of the parties also suggest that there is a need to review and revise certain policies and/or rules regarding some aspects of distribution service to allow further customer choice in the market. These discrete issues may be addressed in separate proceedings, but further scoping and informal industry collaboration is probably worthwhile before any formal proceedings into distribution competition are initiated.

The common denominator with these various forms of distribution competition, is that end-users are provided with a choice of services, at a lower cost than what the end-user is currently paying. Thus, distribution competition will allow an electricity consumer to choose who, and which services, can best fit the end-user's needs.

We believe that ORA's definition of distribution competition serves as a useful starting point for analyzing what distribution competition is, and what the CPUC should do about it. Although the term distribution competition suggests competing electric distribution wires companies, the parties have a much broader vision of what distribution competition is. Not only does distribution competition include distributed generation and competition for customers by publicly owned electric utilities, it also involves the unbundling of various distribution services that result in more competitive alternatives.

In considering possible changes to the current system of electricity distribution, we should keep in mind the policies and goals of AB 1890:

> "It is the intent of the Legislature to ensure that California's transition to a more competitive electricity market structure allows its citizens and businesses to achieve the economic benefits of industry restructuring at the earliest possible date, creates a new market structure that provides competitive, low cost and reliable electric service, provides assurances that electricity customers in the new market will have sufficient information and protection, and preserves California's commitment to developing, diverse, environmentally sensitive electricity resources." (Stats. 1996, Ch. 854, § 1.(a).)

In addition, § 330(k)(3) provides that in order to achieve meaningful wholesale and retail competition in the electric generation market, customers and suppliers need to be provided with open, nondiscriminatory, and comparable access to transmission and distribution services.

We also agree with the comments of some of the consumer groups which contend that all customers, not just large industrial and commercial customers, should benefit from competition in the provisioning of electric distribution services.

The staff's examination of the distribution competition issues should keep these policies and goals in mind. The staff report also needs to identify the barriers which prevent the electric market from fulfilling these policies and goals.

B. Existing Limitations to Distribution Competition

Section 330 contains two subdivisions which address the manner in which distribution systems are to be regulated, and who can own, operate and maintain the distribution systems. Subdivision (f) of § 330 states:

> "The delivery of electricity over transmission and distribution systems is currently regulated, and will continue to be regulated to ensure system safety, reliability, environmental protection, and fair access for all market participants."

Subdivision (r) of § 330 states:

> "Transmission and distribution of electric power remain essential services imbued with the public interest that are provided over facilities owned and maintained by the state's electrical corporations."

The CPUC has also stated, in the Preferred Policy Decision, that the UDCs' role in the restructured electric industry is to "continue their obligation to provide distribution services to all customers, including direct access customers, in their service territories. (Preferred Policy Decision, pp. 85, 207, COL 29, 31; See D.97-09-047, p. 45.)

C. Should the Distribution System Remain a Monopoly?

The vertically integrated electric utility was premised on the idea that a single monopoly provider was the most efficient manner in which to generate, transmit and distribute electricity to end-use customers. With the enactment of the Energy Policy Act of 1992 (Public Law 102-486, 106 Stat. 2776 (1992)), and earlier federal laws, there was a shift away from the vertically integrated monopolies and command-and-control regulation to a policy which looked increasingly toward competition and a greater reliance on market mechanisms.

In the Preferred Policy Decision, the CPUC opened the generation market to competition, and placed the operations of the transmission system into the hands of the ISO. To implement the direct access provisions of AB 1890, the UDCs were required to the do the following:

> "The role of the UDC is to provide distribution services to all customers regardless of their choice of electricity supplier. In addition, the UDC will be required to supply electricity to those customers who choose to remain with their existing electric utility. During the four year transition period, the three largest UDCs must bid all their generation into the PX and purchase power on behalf of the utility service customers from the PX. As the distribution entity the UDC shall be responsible for providing distribution services to customers, and shall also be responsible for service connection and disconnection. The Commission will continue to regulate the rates, terms, and conditions of the distribution and electric services provided by the UDC including, their ability, if any, to engage in competitive market services and transactions in the post-transition era." (D.97-05-040, p. 48, citations and footnote omitted.)

With the increasing availability of distributed generation, the ability to procure electricity from an ESP of the customer's choice, and competition for customers between the publicly owned utilities and the UDCs, the time has come to assess whether the ownership, maintenance and operation of the UDC's distribution system should remain a monopoly.

The parties opposed to the IOUs' continued ownership, maintenance and operational control over the electric distribution system contend that the system is no longer a natural monopoly and that competition should be permitted. Islanded self generation, and distributed generation that remains connected to the distribution system are two examples of why they believe the distribution system should no longer be considered a monopoly. UCAN asserts that the following functions should not be considered monopoly services: distribution system design and construction; distributed generation; commodity power purchases by the UDC for default customers; and metering and billing.

The IOUs contend that the present system of electric distribution should remain the same. PG&E states that the electric distribution function is a natural monopoly which is most efficiently performed by a geographically fixed, single network provider. The IOUs assert that none of the other parties have demonstrated that the UDCs have failed to meet their responsibilities to deliver safe, reliable and affordable electric service to the citizens of California, nor have any of the other parties suggested an alternative that would successfully replace the current electricity distribution system.

The IOUs also contend that § 330(f) mandates that the electric distribution system is to continue as a regulated entity to ensure system safety, reliability, environmental protection and fair access for all market participants. The IOUs state that the competing service providers are seeking nothing more than regulatory intervention so that they can succeed in an already competitive market, and that they are using distribution competition as a vehicle to dismantle the regulated public utility.

Some of the parties suggested that the CPUC should first determine which services could be competitive, and which should remain a monopoly function. If services are competitive, they should be unbundled from the distribution services. If the service is best left to a regulated, single provider, then the CPUC should examine whether there are market power issues associated with being a monopoly provider. The CPUC should also consider whether the monopoly provider of a particular service makes the most economic sense, and whether the monopoly service is the best way of facilitating customer choice of generation suppliers and direct access, while providing the best protection for consumers. In the study, staff should assess whether certain distribution services should be unbundled.

D. Competition by Publicly Owned Utilities

The provisioning of electric service to end-use customers who are located in close proximity to, or in the same service territory as, the UDCs, is one of the most frequently cited examples of distribution competition.

The publicly owned entities contend that their right to offer electricity service has long been codified in various statutes. The publicly owned entities and the agricultural interests point out that irrigation districts have had the authority to generate, transmit and distribute electricity pursuant to Water Code § 22115. Irrigation districts also have the right to sell electricity to customers within their boundaries, as well as to others located outside of their borders, subject to the reasonable rules, regulations, and orders of the governing body of the cities or area being served. (Water Code §§ 22115, 22120, and 22123.) In addition, a municipal corporation is specifically permitted to form an electric utility to serve customers both within and outside its boundaries with certain limitations. (Cal. Const., Art. 11, § 9.) The Public Utilities Code also allows utilities owned by municipal corporations and municipal utility districts to sell surplus power outside their area. (Pub. Util. Code §§ 10005, 12804.)

The publicly owned entities and other parties assert that if the citizens of a particular locality and local government want a choice of electric providers, that these publicly owned entities should be allowed to compete. As long as there are other entities willing to bear the risk of providing electricity, they argue, that California's electricity consumers should not be denied access to electric distribution service options that are comparable to, or outperform those of the UDCs.

The builders and the publicly owned utilities also point out that the areas where the UDCs are facing competition are in greenfields, i.e., in new residential or commercial developments. Since the distribution system for the new development will be all new construction, the choice for the developers is whether the publicly owned utilities can provide cheaper electric distribution service infrastructure costs than the UDC serving the area.

Some of the publicly owned utilities argue that the UDCs simply do not want any competition in their service territories. Even though the UDCs complain that they are disadvantaged because of their averaged rate structure, when they are faced with competition from a publicly owned utility, the UDCs resist relinquishing any of their rural customers.

The city governments point out that to the extent that distribution competition involves the construction of competing wire systems, competitors will need a franchise from local franchising authorities (usually the cities or counties) in order to utilize property and right of way owned by the relevant local jurisdictional entity.

The IOUs contend that the lower rates of the publicly owned entities are not attributable to efficiency. Instead, they assert that the publicly owned utilities can offer lower rates because they do not have to offer averaged rates, and because they can use their tax exempt status to obtain low cost financing. In addition, the publicly owned entities can use long term contracts to lock up customers. As a result, the IOUs assert that those advantages allow the publicly owned entities to selectively choose who they want as customers. The IOUs suggest that the CPUC might want to encourage a review of the tax advantages by the appropriate authorities, and to provide the UDCs with pricing flexibility to combat this form of bypass. SDG&E/SoCalGas contend that § 378 authorizes the UDCs to offer flexible rates.

SCE contends that the irrigation districts are offering electric service well beyond the needs of the agricultural communities that they are supposed to serve, as well as outside their historical service areas. The IOUs and some of the other parties infer that action should be taken to limit this activity.

A variety of concerns and issues have been raised about the publicly owned entities and their provisioning of electric service in competition with the services offered by a UDC. The following are some of our concerns.

If direct wires competition becomes more prevalent, instead of just in new developments, the UDCs may face losses in their current customer base, as well as their revenues. These reductions could have an adverse impact on the remaining customers of the UDCs because of possible stranded electric distribution facilities. The staff study should address the impact of distribution competition on stranded costs.

The IOUs contend that they need to be given rate flexibility in order to retain customers. ORA suggests that before the CPUC decides whether the UDCs should be given tools to compete with the publicly owned utilities, more information on the factors which give the publicly owned utilities a cost advantage needs to be gathered. ORA also suggests that the rates of the publicly owned utilities help to limit the UDC's rates. The staff study should consider the rate flexibility proposal from the perspective of whether the rates will unfairly shift costs to other customers.

Another concern is the safety standards that publicly owned utilities and private distribution owners follow when constructing and inspecting electric distribution facilities. The CPUC has jurisdiction over the safety aspects of the electrical systems of publicly owned utilities, and has established safety, construction, inspection and maintenance standards applicable to them. (See Pub. Util. Code §§8001-8057; Polk v. City of Los Angeles (1945) 26 Cal.2d 519, 540; D.98-03-036; D.98-10-059.)

If direct wires competition exists between a publicly owned utility and the UDC, the question arises as to which entity has the obligation to serve the customers in that area. This question highlights the "cherry picking" argument and requires a determination whether the UDC should be left with the burden of having to serve the customers that the publicly owned utility does not plan to serve. The staff study should examine whether the Legislature should consider clarifying who has the obligation to serve under such circumstances.

Another concern is over the public purpose programs that the UDCs and the publicly owned entities are required to provide. At the present time, the UDCs, through Commission decisions and statutes, are obligated to provide certain programs. Although the publicly owned utilities are under a similar obligation, the same programs that the UDCs have, may not be offered by the publicly owned utility. (See Pub. Util. Code §§ 381, 382, 385.) For example, the rate discount and program for affordable electricity for low income customers may vary depending upon whether the customer is served by a UDC or a publicly owned utility. The policy question that the Legislature may want to address is whether the publicly owned utilities should have to offer the same public purpose programs as the UDCs.

The IOUs, and some of the other parties, expressed concerns over the tax advantages that the publicly owned utilities have, and whether limitations should be placed on the ability of the publicly owned utilities to extend their customer base. These are issues which the Legislature needs to decide since the CPUC lacks jurisdiction over the publicly owned utilities. In addition, existing statutes permit the publicly owned utilities to supply electricity within and outside their boundaries. The Legislature will need to be involved if the stakeholders believe that the competitive practices of the publicly owned utilities need reform. Due to the existing statutes that authorize the publicly owned utilities to offer electric service, today's decision does not adopt any measures which limit the authority of those entities.

Much of the focus regarding competition by the publicly owned utilities has been on two resolutions adopted by the CPUC. The resolutions rendered advisory opinions on whether the proposed electric service would impair the UDC's ability to provide adequate service at reasonable rates in the remainder of the UDC's service territory. In Resolutions E-3528 and E-3549, the Commission rendered opinions stating that the formation of the proposed irrigation districts would not substantially impair the ability of PG&E to provide adequate service at reasonable rates in the remainder of PG&E's service territory. Resolution E-3528 also stated:

> "The discipline of the marketplace mitigates the impact of the construction of duplicative facilities on PG&E and its customers. Allowing for the construction of duplicative facilities provides a competitive check on the ability of the utility to pass through unreasonable costs through to ratepayers in distribution rates and provides discipline to both the utility and the Commission in determining the rate design for distribution services. Uneconomic bypass of existing utility facilities shows areas where our ratedesign [sic] is economically inefficient and highlights areas where reform of our rate design may make sense. In addition, the provision of duplicative systems in this area will increase the level of competition available to the

> customers in this area, even those that remain with PG&E."[38]

In addition to the resolutions, the CPUC has addressed the Competition Transition Charge (CTC) exemptions in AB 1890 that are available to the irrigation districts, and provided comments to the FERC on the Laguna Irrigation District's (Laguna) application for interconnection. In D.97-09-047 and Resolution E-3531, the CPUC articulated a policy in favor of promoting competition by irrigation districts that received the CTC exemptions contained in § 374. In its comments to the FERC, the CPUC supported Laguna's application. The comments cited a passage from D.98-06-020 that the CPUC's "policy is to promote competition in all markets where competition may be economic." (D.98-06-020, p. 7.)

Since we are likely to encounter similar distribution competition issues before the staff study is completed and before a policy on distribution competition is adopted by the CPUC, it is appropriate to provide direction to the parties. Consistent with our recent actions concerning the legislatively mandated CTC exemptions, we will continue to favor distribution competition from irrigation districts that have received CTC exemptions. In the absence of legislation promoting distribution level competition, we will maintain the status quo regarding the broader issues of distribution competition. If distribution competition issues are raised in the context of facilitating distributed generation, those competition issues will be addressed in the new distributed generation

[38] In denying rehearing of Resolution E-3528, the CPUC stated in D.99-03-062 at page 2 that the language in the resolution regarding duplication of facilities was "dicta," that it was not essential to the holdings of the resolution, and did not serve as precedent or rescind, alter, or amend any previous CPUC order.

rulemaking. Accordingly, the CPUC will look toward currently applicable policy decisions and orders to resolve issues relating to distribution competition.

E. Privately Owned Distribution Systems and Facilities

EPUC/CAC state that AB 1890 opened the generation market to competition. As a result, a load can be served by the UDC, a non-utility aggregator, or a non-utility generator. If a load is located near a non-utility generator, EPUC/CAC assert that it may be more efficient to serve the load using privately owned distribution facilities. They note that this is expressly permitted under § 218 for cogeneration facilities, and that transactions which fall within the definition of "on site" (218(b)(2), "over the fence" (218(b)(2), or "own use"(218(a), (b)(1)), are not subject to regulation by the Commission. EPUC/CAC specifically propose that the CPUC consider the following:

- Authorize non-UDC development and ownership of distribution facilities without subjecting the facilities to rate regulation;
- Authorize the use of existing, privately owned distribution facilities to deliver distributed generation to third party users without subjecting the facilities to rate regulation;
- Permit UDC customers receiving service over dedicated distribution facilities to purchase and own the facilities and consider alternatives to ensure continued reliability in operating these facilities; and
- Permit generators to construct or purchase and own special facilities used to interconnect the generating facilities to the T&D grid.

Other parties also advocate that non-UDCs be permitted to construct, own, and operate the distribution facilities without any oversight or control by the local UDC. They contend that this would increase customer choice, reduce costs, and provide end-users with better access to the competitive commodity and ancillary services markets.

EPUC/CAC state that large users in some cases are interconnected with the UDC through dedicated distribution facilities. For example, a customer may interconnect with the UDC at a distribution voltage through a series of UDC owned facilities, such as a substation, which transforms the power from the transmission voltage. The customer in such circumstances typically has been required to pay for these facilities through a special facilities agreement. Not only is the customer responsible for the cost of installing the distribution facilities, but it is also required to pay the UDC an operation and maintenance charge for as long as service is provided by the UDC. EPUC/CAC contend that this can result in higher costs than if the customer had purchased or constructed and maintained ownership of the facilities. EPUC/CAC recommend that the CPUC examine whether the customers should be permitted to provide these O&M services.

EPUC/CAC, as well as the California Department of General Services, contend that this problem could be eliminated if the customer was permitted to own the facilities, either through direct construction or through acquisition from the utility.

Competisys LLC (Competisys) states that the CPUC should consider a model by which private property owners can choose among competing distribution service providers, including the UDC. Competisys proposes that these distribution service providers file tariffs with the CPUC without the need for any rate cases or approvals. The customer of the distribution service provider could then choose their ESP.

ORA notes that another form of distribution competition is the purchasing or leasing of a dedicated substation and changing the voltage level of service. ORA asserts that savings can be realized by bypassing the UDC's distribution system, and that such savings exceed those available from choosing direct access. Private distribution service can provide substations and line extensions to customers at a fraction of the utility cost.

The IOUs oppose the proposals to expand third party ownership of distribution facilities because it would create private distribution systems that would offer rates to selected customers with little or no CPUC oversight. These distribution service providers would have no obligation to serve all willing customers, and such systems might still have to rely on the UDC's distribution system for backup or reliability. In addition, the construction and safety standards for these private systems could vary from one jurisdiction to another.

PG&E contends that if private distribution systems are allowed, that this could result in a significant transfer of jurisdiction over the distribution service from the CPUC to the FERC, because the UDCs would be wheeling wholesale energy for the private distribution providers, rather than engaging in a retail transaction. PG&E contends that FERC has claimed exclusive jurisdiction over local distribution facilities when the facilities are used to serve wholesale customers.

SCE states that third party ownership of distribution facilities can occur in two ways. The first is where the customer is permitted to own dedicated distribution facilities and substations which presumably serve only the customer and are sited on the customer's premises. The second situation is where the third party owns and operates the distribution facilities serving not only the customer but other customers on the distribution grid. SCE says that under its tariffs, customers are permitted to own and operate their own distribution facilities. SCE notes that there is an issue about whether the customer owning the distribution facility is a public utility subject to regulation under § 216.

The issues surrounding private distribution systems are very similar to the issues that confront us with respect to distribution competition by publicly owned utilities. Among the more important issues of private ownership and operation of a distribution system, are safety and jurisdiction. We discuss those issues below.

The safety concerns with private distribution systems include safe and reliable interconnection with the UDC's distribution system, and the type of safety and construction standards that private systems should adhere to. If private distribution systems are permitted to be built, some parties contend that the construction and operation of such facilities may differ from what is required of UDC distribution facilities. If the standards differ, it may pose safety risks to facilities and to personnel. Different standards could also result in reliability problems for the UDC's distribution system. Also, if the standards vary, the interconnection may be more complex, which may result in higher costs than a standardized interconnection.

If the private distribution facility is considered a public utility, then the CPUC would be able to require the owner of the private distribution facilities to adhere to certain electrical safety and construction standards.[39] However, if the private distribution facility is not considered a public utility, then the Legislature might want to consider whether it should mandate that all privately owned distribution facilities follow certain safety standards.

---

[39] Even if the private electric distribution facility is not a public utility, construction of any electrical lines must still abide by the requirements of §§ 8001-8057.

If the rules are relaxed to permit more privately owned distribution facilities, the issue arises as to whether the ownership of such facilities would be considered a public utility. If the privately owned distribution system uses cogeneration technology, a non-conventional power source, or landfill gas technology, for the generation of electricity, which is used in accordance with § 218 (b) or (c), then it would not be considered a public utility. (Pub. Util. Code § 216(i).)

If the privately owned distribution facility is used for direct transactions or participation directly or indirectly in direct transactions, or for sales into the Power Exchange, one could argue that the privately owned facility is considered "electric plant,"[40] and because of its use in these types of transactions, § 216(i) exempts it from regulation as a public utility. It is not clear, however, whether the Legislature intended to exempt a privately owned distribution system and generating facility from the CPUC's jurisdiction. This is an issue that the Legislature may want to clarify.

If privately owned distribution facilities are allowed, the obligation to serve issue arises as well. As we discussed in the publicly owned utility discussion, the Legislature may want to determine which entity has the obligation to serve customers when there are two or more competing electric distribution companies in the same area.

The issue of whether third parties should be allowed to design, construct, own, and operate distribution facilities on private property, and the issue of whether customers should be permitted to purchase special facilities that were built to interconnect a customer to the UDC's distribution system, are

[40] The term "electric plant" is defined in § 217.

issues that the staff study should explore. The staff study should determine whether the UDC's control over the design, construction, ownership, and operation of distribution facilities is really needed. The study should determine whether the need for safety and reliability of both the private distribution system, and its interconnection to the UDC's system justify continuation of these restrictions. The study should consider whether the lifting of such restrictions would require any legislative changes to § 330(f) or to any other statutory provisions.

F. Line Extensions

An issue that is related to the privately owned distribution systems and facilities is that of line extensions.

Rule 15 of the UDCs' tariffs cover the extension of electric distribution lines to provide service to customers. This rule provides that the UDCs are responsible for the planning, design, and engineering of distribution line and service extensions using the UDC's standards for material, design, and construction. New residential applicants, however, may use the Applicant Design and Applicant Installation provisions of the rule and hire a qualified contractor or sub-contractor to design and/or build the distribution line extension subject to the UDC's standards and approval. The distribution line extension facilities installed under this rule are then owned, operated, and maintained by the UDC.

Rule 15 further provides that the UDC will complete the distribution line extension without charge, provided that the UDC's total estimate for the installed costs do not exceed the allowances from permanent, bona-fide loads served by the line extension within a reasonable time, as determined by the UDC. Applicants are responsible for excavation, substructures and conduits, and protective structures in underground line extensions, which the UDC may perform when requested by the applicant. Contributions or advances by an applicant to the UDC for the installation of the line extensions are taxable and include an Income Tax Component of Contribution (ITCC) at a rate provided in the UDC's preliminary statement tariff.

Several parties take issue with the UDCs' current line extension rules, and urge that a comprehensive or partial review of the line extension rules take place. The Utility Reform Network (TURN) contends that the CPUC needs to assign all line and service extension costs to the new customer, rather than assigning large portions of those costs to the UDC's existing customers.[41] TURN contends that the current practice helps subsidize a new customer's hook up costs. TURN contends that if new residential customers were required to fund their own line and service extensions, that they could obtain lower cost financing by including the cost in their mortgage, and avoid paying the ITCC.

The developers urge the Commission to revisit the line extension rules and expand private ownership of distribution facilities. They complain about the additional costs imposed on developers because of the ITCC. They note that this tax is not required when a public utility district provides distribution line extensions to builders and developers.

Some parties also favor the unbundling of the construction of distribution facilities or of the line extensions. They believe that cost savings are likely to result if competition in the construction of facilities is permitted.

[41] TURN cites D.94-12-026 and D.97-12-098 as examples of where the CPUC assigned more of the costs to new customers.

PG&E supports the CPUC's general policy in the line extension proceeding (R.92-03-050) of adjusting line extension allowances to avoid subsidization of new customer connections. However, PG&E believes that this policy can still create market distortions when the ITCC is taken into account. According to PG&E, this situation prevents it from effectively competing with irrigation or public utility districts, which are not bound by this policy or subject to the tax.

PG&E further notes that § 783 is inflexible, with a statutorily mandated complicated process that one must go through before any changes to the line extension rules can be made. Since the statute does not apply to irrigation districts, they can change their line extension rules on short notice, thus making them more attractive to developers in competitive situations. PG&E recommends that the CPUC support legislative changes to § 783. PG&E also recommends that the CPUC initiate a new phase in the line extension proceeding to provide the UDCs with new competitive options to meet line extension competition and to streamline the rules.

During the last several years, the CPUC has taken steps toward improving the line extension rules by issuing a number of decisions. We recognize, however, that these changes do not sufficiently address the concerns that the parties have raised in this proceeding. In addition, the steps that are detailed in § 783 can lead to a cumbersome and time-consuming process to change the line extension rules. Should an appropriate legislative measure be proposed to amend § 783, we will consider supporting it if it meets our goal of expanding choices to consumers, does not affect safety or reliability, and results in cost savings without cost shifting.

As competitive pressures grow, there will be a need for UDCs to respond quickly to potential threats of competition. The line extension rules should reflect those competitive influences. In the interim, the line extension proceeding shall continue to be the proceeding in which parties can seek to reform the line extension rules.[42] The CPUC staff is directed to examine in its study whether more comprehensive changes need to be made to the line extension rules.

G. Wires Only Company

Several of the parties have suggested that the UDC be transformed into a wires only company. Although no one specifically defined what that means, it appears that most of the services now provided by the UDC, would be unbundled, and the UDC would only operate the distribution system to transport and deliver electrical energy between buyers and sellers.

If the only task of the UDC is to transport and deliver energy over the distribution system, that leaves open the question of who will provide end-use customers with their electricity. A new mechanism would have to be created to assign to each end-use customer, except for those end-users who previously selected a direct access ESP, a commodity default provider. In addition, we would have to determine which ESP would be the provider of last resort.[43] Other services would also have to be unbundled, which would require new mechanisms to sort out which companies can offer what kind of services and under what terms and conditions.

---

[42] If the interconnection rules are impacted by the line extension rules, the interconnection workshop process should consider addressing the related line extension rules at the same time.

[43] We discuss the issues related to the UDC's role as the default provider and provider of last resort later on in this decision.

The parties who favor a wires only company contend that this would mitigate the incumbent UDC's market power in the retail electric market, and provide all of the market entrants the opportunity to compete on the same level. Transforming the UDC into a wires only company will help ensure that customers and suppliers will have "open, nondiscriminatory, and comparable access " to distribution services. (Pub. Util. Code § 330(k)(3).)

Before a wires only company can be created, §330 (f) and (r) may require changes. Instead of a regulated electrical corporation owning and maintaining the distribution system, some of these functions could be performed by other entities.

The staff should study the proposal for a wires only company. A careful analysis is needed to determine what, if any, distribution services should be unbundled, and how these unbundled distribution services will be provided. Staff should also consider what type of regulatory framework would be needed to accommodate these kinds of changes.

H. Independent Distribution Operator

ORA and UCAN have suggested that the operation, and possibly the maintenance, of the distribution systems be transferred to an IDO. Such a proposal is similar to the ISO's role of operating the utility-owned transmission facilities. Others have suggested that the ISO undertake the role of the IDO. The cost of creating an IDO is also a consideration, as evidenced by the cost to establish the ISO.

The IDO concept may fit into a regulatory framework that includes wires-only distribution companies. The IDO concept could ensure that the UDCs would not receive any preferential treatment.

The staff study should examine the advantages and disadvantages of allowing an IDO to operate the electric distribution system. The study should also look at how the IDO could be funded, and consider whether the ISO's responsibilities should be enlarged to take on the role of an IDO.

I. Rights of Way

In order to have facilities based distribution competition, one requires access to rights of way. ORA proposes a separation of distribution service from the management of the distribution rights of way. In essence, this would allow open access to rights of way.

ORA points out that the opening of rights of way to competition has already been adopted for the telecommunications industry in D.98-10-058. ORA contends that a similar policy could make electric distribution competition a reality, while preserving rights of ways as a regulated monopoly. A public purpose fee could also be collected for usage of distribution rights of way to support service in high cost areas, and to recover any stranded costs.

PG&E points out that an open access rights of way policy is not feasible because each city controls the franchises, and that the IOU in a particular locality cannot issue subfranchises. This is supported by the comments of the cities of Burbank and Glendale, which state that to the extent that competing wire systems are built, competitors will need a franchise from local authorities in order to utilize property and rights of way owned by these entities. Thus, local governments will have primary jurisdiction to determine whether there will be wires distribution competition within an entity's jurisdictional boundaries.

The rights of way proposal is dependent upon a policy of whether duplicate facilities should be promoted. In addition, the cooperation and consent of the many cities and counties throughout California would be needed.

Duplicate electric facilities alongside the same trench or pole might also pose safety or reliability related problems, or they might violate some of the provisions of General Orders 95 and 128. These issues should be studied by the staff when assessing the rights of way proposal.

J. Master Metering and Submetering

Master metering is a situation where a residential or non-residential property owner receives all of its electrical energy through a single master meter. Electrical wires then feed the electricity to the various tenants of the property. In some commercial buildings, tenants are individually metered, served by, and billed by the UDC. In other existing commercial buildings, the master meter situation is typical. In this situation, the tenant's electricity charge is reflected in the rent, which does not vary with the amount of electricity that the tenant consumes. The electricity bill for the entire building is usually apportioned to each tenant based on the square footage that each tenant occupies.

Submetering allows the property owner to measure and bill the amount of electricity usage by each tenant. The electricity flows from the distribution system to the service lateral, to the property owner's master meter, and to the submeters of each tenant. Submetering can be found in some older multi-unit residential structures, in older mobile home parks, in recreational vehicle parks, and at boat marinas. (See Pub. Util. Code §§ 780.5, 2791(c); Harb. & Nav. Code § 630.).) Since 1962, the CPUC has prohibited the resale of electricity by non-domestic customers through submetering. (D.63562 (59 CPUC 547); D.92109 (4 CPUC2d 179).)

Several of the parties who commented on distribution competition suggest that the CPUC needs to address master metering issues. They point out that the current restrictions against submetering in commercial buildings are outdated. They believe that these restrictions need to be reassessed in light of the choices that end-use customers have in the generation market, as well as the potential deployment of DER technologies and strategies.

The parties who favor a review of the prohibition against master metering contend that individual tenants end up paying more for electricity than if the property owner is able to aggregate load through a master meter. In addition to increasing the UDC's revenues, individual meters for each tenant increases construction costs due to the space requirements for individual meters. Also, the individual meter requirement increases the cost of tenant buildouts due to the need to reconfigure electric wiring when tenant floor space requirements change. They also state that in commercial properties, the cost of energy is the single, largest line item operating cost, and that property owners should be allowed to maximize their ability to reduce these costs.

Other large users contend that allowing property owners to aggregate load into a single master meter would allow them to use more comprehensive DSM techniques in new construction. If these techniques were used, it could result in "smart" buildings that have energy demand responsiveness capabilities. They believe that the current individual metering requirements impedes their ability to use such techniques.

PG&E and SCE oppose removing the prohibition against the submetering of commercial properties. PG&E asserts that the parties' master metering and submetering proposals will result in the creation of private distribution systems. PG&E contends that such systems are on a decline and should not be revived because of the problems associated with safety, reliability, and cost, as the experience with mobile home parks has shown. PG&E also states that contrary to the parties' assertions that deleting the submetering prohibition will result in energy conservation, the CPUC and the Legislature imposed the restrictions to encourage energy conservation by individual customers. PG&E also asserts that submetering would defeat the purpose of direct access because it removes the tenant's ability to choose its own ESP. Instead, the submetered tenant would be dependent on the landlord's choice of electricity options.

SCE states that current tariff rules require individually metered service, and that master metering and consumption based resale of electricity is expressly prohibited. SCE contends that the CPUC has long supported a policy of preventing situations that would place an unregulated entity into the utility business without affording the end-use customer any recourse as to the rates and conditions of service. SCE recommends that the CPUC continue to support its policy of prohibiting physical aggregation of customer accounts.

SCE also states that the aggregation of multiple service accounts into a single service account (master meter) is nothing but an attempt to avoid distribution infrastructure charges. SCE contends that this type of aggregation does not result in overall cost savings. Instead, it merely shifts costs from one group of customers to another.

It is clear that the prohibition against submetering of commercial buildings was adopted long before a change to a competitive electric market was contemplated. With the introduction of the restructured electric market and direct access, the CPUC recognized in footnote 15 of D.97-05-040 that the issue of master meters and direct access should be addressed.[44] The issues regarding master metering and submetering should be considered in the CPUC staff study

---

[44] In D.97-10-087 at page 21, the CPUC allowed master metered customers, who provide submetered tenant billing, to participate in direct access as a single account.

and report. Staff is directed to address these issues, and to provide us with recommendations as to how these issues should best be handled.

There are a number of issues raised by submetering that require further thought. First, we must determine whether the existing prohibition against submetering in commercial properties and other locations is consistent with AB 1890's intent of providing end-use customers with competitive, low cost and reliable electric service. (Stats. 1996, ch. 854, § 1.(a).) We should also examine whether submetering will effectively limit an end-user's choice of whom it wants as its ESP, or whether the ability to aggregate many separate accounts into one large account will provide greater benefits to end-users. If it is the latter, then we will recommend to the Legislature amendment of § 330(k)(2).

Second, we should determine if the submetering technology is capable of providing accurate and reliable meter usage data. Such an inquiry could include whether meter design specifications are needed for submeters. Also, some coordination with local governmental agencies, who are responsible for the accuracy of weights and measures, may be needed to ensure that any submeters used by a property owner remain accurate.

Third, if submetering is permitted, the Legislature should consider whether amendment of § 739.5 is necessary to ensure that the submetered tenants of commercial buildings are billed at the same rate that the property owner pays for the electricity. That is, should all of the cost savings or discounts that the property owner receives from the utility be passed directly through to the submetered tenant? If on-site distributed generation is used to generate electricity for the building tenants, the Legislature may need to consider what rate the submetered tenants should be charged. Consideration of how much submetered tenants should be charged would help resolve some of the concern that the UDCs raised concerning the creation of an unregulated private distribution system.

And fourth, we need to consider whether any changes to the direct access procedures will be necessary. That is, since the choice of selecting an ESP is up to the customer, should the master metered customer be allowed to make the choice, or should submetered end-use customers be entitled to have a voice in the selection of the ESP.

K. Public Purpose Programs

Section 381 requires the UDCs to collect from its customers a charge to fund certain public purpose programs that are described in § 381(b) and in § 382.[45] This charge is included as part of the local distribution charge, and is to be collected on the basis of usage.

The public purpose programs that are funded by this charge include: energy efficiency and conservation activities; public interest research and development; operation and development of renewable resource technologies; and programs provided to low income electricity customers that include energy efficiency services and the CARE program. Most of the monies collected are used to fund these programs in the UDCs' service territories. The rest of the monies are transferred to the CEC, which then allocates the funds with the approval of the Legislature. (Pub. Util. Code §§ 381, 382.)

If distribution competition occurs, either through distributed generation or some other form such as service by a publicly owned utility, this public purpose charge might not be collected by the UDCs. That is, this charge

[45] The reference in § 382 to the California Alternate Rates for Energy (CARE) program is further described in §§ 739.1 and 739.2.

will not be collected if an end-use customer bypasses the electric distribution system entirely, or does not use the distribution system during a billing cycle. As a result, these public purpose programs could experience a decrease in funding.

Publicly owned utilities are obligated under § 385 to collect a similar usage-based charge on local distribution service. The monies collected fund similar kinds of public purpose programs in the publicly owned utilities' territory.

In D.97-02-014 and D.99-03-056, the CPUC recognized that programs such as energy efficiency and low income assistance programs would change in a competitive electric market. In D.99-03-056, the CPUC expressed the view that the administration of the energy efficiency programs should be moved to a non-utility program administrator, and that the administration of the low income assistance programs could remain with the UDCs, or be taken over by some other entity.

The Latino Issues Forum (LIF) and the Greenlining Institute (Greenlining) state that the Commission must examine the mechanisms that will ensure the long term future of public purpose programs, including low-income and energy efficiency programs. They point out that the existing public purpose programs, including low income and energy efficiency programs, play a vital role in promoting energy efficiency and provide universal access to an essential commodity. They expressed the concern that distribution competition may impact the level of funding for these programs.

LIF/Greenlining also argue that the publicly owned utilities should be required to have the same kinds of public purpose programs as the UDCs. They point out that the publicly owned utilities are not required to offer the same kind of low income assistance programs that the UDCs are required to offer. The parties opposed to such a mandate point out that § 385 already requires the publicly owned utilities to offer equivalent kinds of public purpose programs.

SCE states that to the extent that more distribution services are provided by municipal utilities and public agencies, the UDCs' current level of expenditures on energy efficiency, renewables, and low income programs may be substantially reduced.

Others expressed the opinion that the public purpose program charges be unbundled from the distribution charge, and that other parties be provided with the opportunity to offer such services. CMA does not see a need for mandated energy efficiency programs, and believes that the offering of such services should be left to the market.

Various parties have suggested ways in which to recover any lost funds for the public purpose programs. These suggestions include shifting the charge to gas distribution, imposing a consumption or electricity production tax, or collecting fees for usage of the distribution rights of way.

Both the CPUC and the Legislature have recognized that electricity is an essential commodity. (Pub. Util. Code §§ 330(r), 391(a); D.97-10-087, p. 41; D.97-05-040, p. 49.) As an essential commodity that "is of utmost importance to the safety, health, and welfare of the states's citizenry,"[46] we intend to ensure that every residential energy consumer in California be able to afford the cost of electricity and natural gas. We plan to continue our commitment to programs which provide rate discounts to low income customers for their energy needs.[47]

---

[46] See § 330(g).

[47] The CPUC is examining how the CARE and low income energy efficiency programs should be administered beyond 2001 in R.98-07-037.

When AB 1890 was enacted, the Legislature specifically stated its intent was "to continue to fund low-income ratepayer assistance programs...." (Stats. 1996, ch. 854, § 1(d).)

With respect to the energy efficiency programs, the CPUC stated in D.97-02-014 that funding for energy efficiency was transitional pending the development of a competitive market. D.97-02-014 stated that one of the goals of a competitive market would be "to ultimately privatize the provision of cost-effective energy efficiency services so that customers seek and obtain these services in the private, competitive market." In D.99-03-056, the CPUC solicited comments on whether funding for energy efficiency programs should be continued beyond 2001. The issue about the future of energy efficiency programs should be resolved in that proceeding, R.98-07-037, or in another appropriate forum.

As we noted earlier in this decision, we have no jurisdiction over the publicly owned utilities. We recognize the concern that there may be disparities between the size of the low income discounts that a customer might receive from a UDC as opposed to the discount that the publicly owned utility offers. Other kinds of disparities between the public purpose programs offered by the two forms of utilities may also be prevalent. However, if these disparities exist, the Legislature will need to address those problems.

SCE points out that if more end-users bypass the UDCs' systems, that expenditures for the public purpose programs will be reduced. The staff study should examine the possible funding problems that might result from bypass, and suggest ways in which these problems can be resolved.

L. Distribution Competition Rate Design and Stranded Cost Issues

As several of the parties pointed out in their comments, the rate design and stranded cost issues associated with distribution competition are very similar to the same kinds of issues that we are faced with in distributed generation. The rate design issues for distribution competition include bypass charges, standby charges, rate flexibility to retain customers, and extended notice before an end-user is permitted to leave the distribution system. The stranded cost issues for distribution competition are very similar as well. The discussion of the rate design and stranded cost issues in the distributed generation section of this decision are equally applicable to distribution competition and will not be repeated here.

Additional arguments and counter-arguments have been raised about the recovery of stranded costs. The parties who oppose the recovery of stranded costs by the UDCs contend that the UDCs have always been faced with the threat of competition by the publicly owned utilities. They assert that the statutory authorization allowing these entities to compete have been on the books for a long time, and that the risk that the UDCs could face competition was included in the UDCs' rate of return. In addition, stranded cost recovery should not be permitted because the changes that are occurring in distribution competition are due to competitive changes that are distinct from the changes that were mandated in AB 1890.

The IOUs contend that if distribution competition is allowed, they should be allowed to recover stranded distribution costs. They point out that the T&D system is the purest example of the UDCs' obligation to serve, and that when the infrastructure investments were made, no one contemplated that distribution competition would occur. In addition, regulatory and legislative policies had an impact on distribution costs, and that these costs have been reviewed and accepted by the CPUC.

Our approach to stranded costs and rate design issues for distribution competition will follow the same analysis described in the distributed generation section. The staff will need to look at the interrelationship between the various rate design issues and the stranded costs issues, and develop proposals for the CPUC to consider. However, before the CPUC can fully consider these rate design proposals, it needs to determine, in conjunction with the Legislature, what the future landscape for distribution competition is going to look like. As described in the other distribution competition sections, the CPUC staff will examine the different forms of distribution competition that may materialize, and the role of the UDCs in each of those scenarios.

Since the distributed generation issues will be handled in a more expedient manner in a new rulemaking, certain rate design and stranded cost issues will be addressed before the staff study is completed. We also recognize that the UDCs have proposed certain charges in other proceedings that are currently pending before the CPUC. We expect the presiding officers, in each of the proceedings where such issues have been raised, to coordinate their efforts to determine where the issues can best be handled. If the issues are handled sooner rather than later, that does not preclude the CPUC from revisiting the issues once the staff report comes out.

VIII. The Retail Competitive Market and the Role of the UDC

A. Introduction

Initial steps to restructure California's electricity market have focused on encouraging competition in the wholesale generation market with the establishment of the Power Exchange and the ISO. Competition in the retail market has also been the focus of restructuring efforts by allowing all customers to choose their electricity suppliers. In addition, competition has emerged in the provision of other services such as metering, metering-related services, and billing. Amidst these significant changes, the role and responsibilities of the UDC with respect to continuing as the exclusive provider of distribution services, and the default provider of electricity, billing, metering and meter-related services has remained relatively unchanged.

In several proceedings, including this OIR, parties have begun to raise concerns about the UDC's role in providing both monopoly and competitive retail services[48]. Many parties are concerned about the UDC's role as the default service provider. Also, as we explained in previous sections, the UDC's role may be redefined depending upon what, if any, distribution services are ultimately unbundled, and what, if any, services end-use customers can choose. Since distributed generation is a competitive alternative to bundled electricity service, the role of the UDC may change from a provider and distributor of electricity, to that of a wheeler, distributor and dispatcher of electricity. Other forms of distribution competition, as well as other structural changes to the retail electric markets, may also affect the current role of the UDC.

[48] Numerous parties in other CPUC proceedings have raised issues about the competitive retail market and the potential for the UDC to act anti-competitively. These issues have been raised in: (1) the post-rate freeze proceeding, A.99-01-016, A.99-01-019, A.99-01-034, (2) Southern California Edison's proposed forward purchases pilot program, A.99.03-062, (3) the electric restructuring rulemaking, R.94-04-031/I.94-04-032, and (4) the proceeding addressing long-run marginal cost pricing for revenue cycle services, A.99-03-013, A.99-03-019, A.99-03-024.

We believe that stakeholders, the CPUC, and the Legislature would benefit from an informal examination of these issues. As the end of the transition period for implementing electric restructuring initiatives draws closer, it is appropriate and timely to evaluate the effects of electric restructuring to date. In particular, we believe a focus on the emerging issues related to the competitive retail market and the role of the UDC is in order. Such an examination must carefully consider whether current policies and rules present undue barriers to competition in the retail market and to what extent customers, particularly residential and small businesses, are benefiting from electric restructuring policies.

Below, we elaborate on specific issues raised by parties that should be addressed in the staff study.

B. The UDC as a Monopoly Provider and Competitive Retail Services Provider

Some parties believe that the UDC has the incentive and the ability to act anti-competitively because it is both the owner and operator of the distribution system and also a provider of competitive retail services such as electricity procurement, and metering and billing services. These parties contend that the UDCs have an incentive to cross-subsidize their competitive retail business operations with the revenues and resources they derive from providing monopoly distribution services.

As discussed earlier in this decision, parties believe that there should be a clear separation between competitive and noncompetitive functions. One proposal is to restrict the UDC to the role of monopoly owner and operator of distribution facilities. They believe that the UDC's continued role, as a competitive service provider, will thwart the development of new technologies and new service offerings. Therefore, the UDC should be prohibited from providing *any* competitive retail services.

An alternative proposal is to allow the UDC to provide competitive services and require the operation of the distribution facilities to be transferred to an IDO. This proposal is similar to the establishment of the ISO to operate the utility-owned transmission facilities.

We do not believe the record in this proceeding supports the dramatic policy modifications proposed by some parties to address anti-competitive incentives by the UDC. Yet, we also must admit that the potential for many of the anti-competitive practices discussed by parties exists as the industry continues to evolve -- practices that could undermine the benefits we intend all consumers to derive from the restructured industry. The industry, consumers, regulators, and the Legislature will benefit from further analysis of current and future industry developments and policy options for a more competitive electricity distribution market. We believe that the Commission's staff should examine the role of the UDC in providing monopoly and competitive services, including the potential for exercising market power. Staff should consider whether it is necessary to identify and functionally separate the utility's retail services business from its distribution operations.

C. Provider of Last Resort and Default Provider

A distinction must be drawn between the "provider of last resort" (POLR) and the "default provider" concepts. The POLR concept is the assumption that a company has an obligation to serve all the customers in its service territory. As service providers compete to provide electricity services to consumers, the POLR has the obligation to provide service to any customer desiring service. For example, the POLR is obligated to provide electricity to customers who do not have a competitive option. On the other hand, the default provider serves customers who, when given a choice of alternative providers, decides to remain with the UDC, or another entity designated as such by regulatory fiat, for electricity service. For example, when the long distance telephone market was opened to competition, if a customer failed to designate who its provider would be, a default provider was assigned to serve that particular customer.

Currently, the UDC's role is to own, operate and maintain the distribution system. (Pub. Util. Code § 330 (f) and (r); Preferred Policy Decision, pp. 85, 207, COL 29, 31; D.97-09-047, p. 45.) In addition, the UDC's role is to provide distribution services to all customers regardless of their choice of electricity supplier. The UDC is considered the default provider of electricity for those who do not elect direct access. (Preferred Policy Decision, p. 85; D.97-05-040, p. 48; D.97-10-087, App. A, § A.(1); Pub. Util. Code § 366(a).) The UDC is also the default provider of billing and metering services. (D.97-12-048, p. 7; D.97-10-087, App. A, p. 2, § A.(1).)

The UDCs' default provider role raises market power concerns because of the large number of customers they currently serve. A number of parties believe that allowing the UDC to continue in its role as the default provider gives the UDC an unfair advantage over other competitors. For example, the UDC could subsidize competitive services, such as metering and meter-related services, with revenues and resources derived from its monopoly and default services. They contend that this allows the UDCs to provide competitive services at a much lower cost than what the competitor can charge.

In the consolidated post-rate freeze proceeding (A.99-01-016, A.99-01-019, A.99-01-034), SCE's proposed forward purchased pilot program (A.99-03-062), and in this OIR, parties have raised the issue of whether the UDCs should be allowed to continue in the default provider role to procure electrical energy for non-direct access customers. DGS believes that the UDC, as the exclusive default provider and, therefore, the largest buyer of electricity, can exercise monopsony power and influence statewide energy prices. Some of these parties propose that the UDCs be required to transfer their respective energy procurement functions to unregulated affiliates, and to unbundle other distribution services as well. Alternatively, ORA proposes that the current requirement that the UDCs procure their energy from the Power Exchange be continued for all of the UDCs' default retail sales. This proposal is being considered in the Commission's post-rate freeze proceeding.

PG&E, SDG&E/SoCalGas, and SCE do not believe that the UDC's role as the monopoly distribution owner and operator, and as the default service provider are in conflict. They believe that the parties who have expressed concerns about the role of the UDC have not demonstrated that the UDCs are failing to meet their responsibilities. The utilities state that parties have not presented an alternative to the UDC's role as both the distribution services and default services provider. In their joint comments, SDG&E/SoCalGas argue that competitive services providers are seeking regulatory devices to succeed in the competitive market rather than rely on their own abilities. PG&E and SDG&E/SoCalGas believe that prohibiting the UDC from being the default services provider unnecessarily limits consumers' choices.

Unbundling the distribution function to allow for competition in discrete aspects of distribution services raises similar issues regarding the UDC as the POLR and default distribution provider. Some of the parties have suggested that if duplicate wires competition is permitted, i.e., the electricity distribution franchise is no longer exclusive, cherry picking of the more desirable customers is likely to result. If the responsibility of the provider of last resort remains with the incumbent UDCs, they may be left serving those distribution customers who cost more to serve.

The EEI states that large, heavily concentrated distribution customers are cheaper to serve than smaller, more dispersed customers. If low and high cost customers are in the same rate class, these cost differences might not be reflected in the distribution rate because of averaged rates. EEI contends that if distribution competitors are permitted to cherry pick the larger customers, an increase in the basic cost of distribution to the remaining customers will result.

The Latino Issues Forum (LIF) and the Greenlining Institute (Greenlining) state that the present system of averaged rates provides economic equality for an essential public service. The ability of publicly owned utilities to cherry pick customers can easily upset the UDCs' average rate structure. LIF/Greenlining urge the Commission to consider the impacts of distribution competition on the average rate structure to ensure that the benefits of the average rate structure are not lost.

SCE contends that reliability problems for the provider of last resort could arise if the distribution system is divided into smaller pieces, so that anyone can operate mini-territories of electric distribution. SCE asserts that this could lead to the alignment of distribution circuits in a manner that reduces the economies associated with distribution-grid integration and reliability, and could also result in the redlining of certain neighborhoods and a shifting of costs.

ORA suggests two different approaches to ensure that all end-users are provided with electric distribution service. The first approach is to require competing distribution companies to take up the same obligation to serve which is currently borne by the incumbent UDCs. The second approach is to establish a high cost fund to provide distribution service to high cost areas. Such a fund would be similar to what the Commission established for the telecommunications industry in D.96-10-066. ORA proposes that all electric distribution companies assess their customers a fee which would be deposited into the fund. A reverse auction would then be held to determine which company would be obligated to serve end-use customers in a certain area. The company seeking the lowest incentive payment would then be awarded the right to provide service to those customers.

As we near the end of the transition period for implementing the electric restructuring initiatives, and as more ESPs and electric distribution competitors enter the market, staff should examine what the role of the UDC should be in the procurement of electricity and the UDC's ability to influence electricity prices. In addition, staff should consider the role of the UDC as the provider of last resort and as the default provider of electricity, billing, metering and meter-related services. The CPUC staff study should examine whether changes to these two roles are needed, or whether other competitors should be permitted to take on these responsibilities. The staff study should address whether the CPUC should consider instituting a new system of determining who the default providers should be, and how they would be assigned to customers, if the necessary electric service elements were unbundled.

The staff study to address these issues is appropriate in light of § 365.5. That section provides:

> "Nothing in this chapter shall prevent the commission from exercising its authority to investigate a process for certification and regulation of the rates, charges, terms, and conditions of default service. If the commission determines that a process for certification and regulation of default service is in the public interest, the commission shall submit its findings and recommendations to the Legislature for approval."

Staff also should consider the impact of competition in distribution services on the obligation to serve, on averaged rates for distribution service, and what, if any, legislative action might be needed to ensure that the obligation to serve all customers is preserved in a competitive environment.

In addressing the POLR and the default provider issue, staff should keep in mind the principles that underlie those two concepts. First, that electricity is a valued and necessary commodity that "is of utmost importance to the safety, health, and welfare of the state's citizenry and economy," and should be provided to everyone at affordable rates. (Pub. Util. Code §§ 330(g), 739(c)(2).), 739.1.) Second, no electric customer must be denied access to any of the components which constitute electric service due to the unwillingness of an electric distribution company to serve a particular geographic area or customer class. (Pub. Util. Code §§ 330(k)(3), 728.)

We recognize that market power and cross subsidization issues have also been raised in other CPUC proceedings pertaining to the restructured electric industry. The CPUC staff in the various proceedings will need to coordinate to ensure that these issues are handled in a timely manner in either the pending proceedings, or addressed in the staff study. It is not our intent to delay resolution of any issues that may have been raised elsewhere, if the other proceeding is the appropriate place to address the issue.

IX. Other Issues

A. Social, Economic and Labor Impacts

The OIR asked parties to comment on the possible social, economic and labor impacts that may result from distributed generation or distribution competition. Some of the parties believe that distributed generation may result in lower prices for electricity, and that distribution competition and distributed generation will lead to an expansion of jobs in these fields. Others contend that if bypass of the distribution system occurs, the UDCs may try to reduce costs which could result in less jobs, and a less qualified labor force. The CCUE comments that if non-utility distributed generation is installed and interconnected with the distribution system, it could have an adverse impact on the safety of utility personnel who work on the distribution system.

It is too early to determine what the social and labor impacts will be, if any. If distributed generation is installed, it is likely that jobs to maintain and operate the equipment will result. If there are job reductions due to less utility workers maintaining the distribution system, other equivalent jobs with privately owned distribution systems or with publicly owned utilities may offset any job losses.

The new rulemaking on distributed generation, and the staff study, should continue to monitor the possible social, economic and labor impacts.

B. Consumer Education

Some parties suggested that an educational effort to inform end-use customers about the availability of distributed generation should be pursued. It was suggested that such a program could use a consumer protection approach to inform customers about what they need to know about distributed generation. None of the parties who commented on this issue have suggested ways in which such a program could be funded. Such an educational program might also be viewed as part of a vendor's overall marketing strategy, which should be borne by the proponent of such technology. We believe this consumer education issue should be addressed in the new rulemaking on distributed generation. Parties interested in this issue should discuss in their testimony in that proceeding whether such efforts should be pursued, and what type of funding mechanisms should be utilized to fund such activities.

C. Impact on Natural Gas Infrastructure

We posed a question in the OIR about the impact of distributed generation and distribution competition on the natural gas infrastructure. We asked this question because a number of existing distributed generation technologies rely on natural gas. The parties who filed comments on this issue recognize that natural gas usage may increase. However, most parties believe that this increase in usage will have little impact upon existing transmission pipeline capacity. The impact is more likely to be felt locally in the area where the natural gas-fueled generator is located. Depending on the circumstances, distribution system or site upgrades may be needed to increase the flow of natural gas to the generators. If upgrades are needed, existing Commission decisions and tariffs regarding natural gas issues should be able to address any cost issues that may arise. As for the parties' comments that the interconnection issues in the gas industry should be consolidated with the electric interconnection issues, and that gas transportation rates should be considered in this OIR, we decline to do so. Those gas issues should be raised in the appropriate gas proceedings.

D. Request and Motions of Solar Development Cooperative

Solar Development Cooperative (SDC) has alleged in its opening comments that the CPUC should "investigate antitrust behavior of Enron/AMOCO and BP Solar's role in their misuse of the Solarex Corporation over the past fifteen years substantially suppressing BI-PV [building integrated-photovoltaic] technology from the American marketplace." (SDC, Opening Comments, pp. 30-33, 36-37.) SDC has also raised this same issue in its August 2, 1999 "Motion to Allow Late Filing of Motion to Compel Discovery and Evidentiary Hearing" and its related "Motion to Compell Discover [sic] and Evidentiary Hearing." Enron Capital & Trade Resources Corporation and Enron Energy Services Inc. filed a response in opposition to SDC's motions.

We have reviewed the allegations in SDC's comments to this OIR, and its motions, as well as the response of the Enron companies. The allegations concern Enron, AMOCO, and British Petroleum (BP), and their involvement with various companies including Advanced Photovoltaic Systems (APS), Solarex Corporation (Solarex), and ARCO Solar. SDC's comments allege that Enron/AMOCO used patents owned by Solarex to sue APS and ARCO Solar and to put them "out of business" for alleged patent infringements involving photovoltaics. According to SDC's comments, BP then took over AMOCO, and Enron's interest was transferred to BP Solar. SDC requests in its comments that the CPUC "investigate this pattern of abuse and suppression within the BI-PV industry over the past fifteen years that has substantially limited mainstream deployment of this important renewable energy technology?" (SDC, Opening Comments, pp. 31-32.)

SDC seeks to have the CPUC open an investigation into the behavior of Enron, AMOCO, and BP with respect to their alleged involvement in photovoltaic patents and related litigation. SDC's request that the CPUC open an investigation into these allegations is denied. In addition, we deny SDC's "Motion to Allow Late Filing of Motion to Compel Discovery and Evidentiary Hearing" and the "Motion to Compell Discover and Evidentiary Hearing."

These three requests are denied because the allegations concern the alleged anti-competitive business practices of the three corporations and their alleged involvement to suppress the deployment of photovoltaics. This alleged anti-competitive behavior suggests that antitrust laws may have been violated.

Antitrust issues of the type that SDC alleges are beyond the jurisdiction of the CPUC. In Northern California Power Agency v. Public Utilities Commission (1971) 5 Cal.3d 370, 377-379, the California Supreme Court held that the CPUC should consider the antitrust implications of the matter before it when it is relevant to the issues of public convenience and necessity which concern the public utility. However, the court quoted from a federal decision which stated that such a consideration of the antitrust implications was "not to suggest, however, that regulatory agencies have jurisdiction to determine violations of the antitrust laws." (Id., p. 377; See Cellular Plus, Inc. v. Superior Court (1993) 14 Cal.App.4th 1224, 1247; D.95-05-020 (59 CPUC2d 665, 684).) That is exactly what SDC is requesting that we do. As SDC stated:

> "In our Opening Comments docketed March 17, 1999, we suggested that the Commission consider a formal review into the history of Enron/AMOCO's abusive and suppressive business practices in regard to photovoltaics the past fifteen years, and establish a Ruling on their misuse of Solarex patents since their takeover of Solarex in 1984. We requested a formal Ruling also be made on how they could use Solarex patents to sue American companies out of business for patent infringement, but then would allow foreign companies to then take those patents (which they did) and do business in competition with Solarex in the United States." (SDC, Opening Comments, p. 31.)

The type of behavior that allegedly occurred does not relate to any application filed with the CPUC by the three companies. Instead, SDC's request seeks to have the CPUC "investigate antitrust behavior."

Furthermore, SDC's allegations that these companies suppressed the use of photovoltaics since 1984 has no relevance to an electrical corporation's provisioning of electricity services to the public. (See Pub. Util. Code § 216(a) and (b).) Thus, the CPUC has no jurisdiction over the subject matter of the allegations that SDC raised in its opening comments.

For the reasons discussed above, the request of SDC to open an investigation into the allegations raised by SDC in its opening comments to this OIR is denied. Since the gravamen of SDC's allegations are contained in the comments to the OIR, and SDC's request to open an investigation is denied, the two related motions of SDC are also denied.

Findings of Fact

1. This OIR was initiated by the CPUC on December 17, 1998, and the CEC and the EOB opened their own dockets on the same issues.
2. The OIR's intent was to identify the range of issues associated with distributed generation, distribution competition, and the role of the UDC in a restructured, retail electric market, and to develop a roadmap to address these issues.
3. A full panel hearing on these issues was held on June 1, 1999.
4. The draft decision of the assigned Commissioner and the assigned ALJ was mailed to the parties on September 21, 1999.
5. Distributed generation and DER are likely to change the way in which end-users obtain electricity and the way in which generation occurs.
6. The ability to generate one's own electricity is a continuation of customer choice, as well as a competitive alternative to bundled distribution service and direct access.
7. Distributed generation is not a new concept.
8. The regulatory structure needs to adapt to the technological and policy changes that are taking place in distributed generation and distribution competition.

9. The term DER includes distributed generation, as well as electric storage technologies, end use technologies, and DSM technologies.

10. Distributed generation, as used in this decision, refers to facilities used to generate electricity and include such technologies as small scale generators or cogenerators using internal combustion engines or microturbines, wind turbines, photovoltaics, and fuel cells.

11. Distributed generation has both advantages and disadvantages.

12. Net metering is defined in § 2827(b)(3).

13. In order to maintain the safety and reliability of the distribution system, one entity should have control over the operation and dispatch of the distribution system.

14. The IOUs are not prevented from owning generation facilities so long as it is consistent with the public interest, and the ownership does not confer an undue competitive advantage on the IOU.

15. The existing interconnection rules are contained in Rule 21 of the IOUs' tariffs.

16. The interconnection of DER to the UDC's distribution system raises numerous safety, technical, and administrative issues.

17. Interim interconnection standards are needed so that the deployment of distributed generation facilities can be facilitated as quickly as possible.

18. The UDCs are currently responsible for the ownership, maintenance, and operation of the electric distribution system.

19. The interconnection of distributed generation is likely to impact the maintenance and operations of the distribution system.

20. Distributed generation on the end-user side of the meter could have significant impacts on distribution system planning, and on transmission system planning and operations.

21. In order for distributed generators to sell their excess capacity to other customers on the distribution system or on the transmission system, the generators will need access to the distribution system.

22. Depending on where distributed generation is sited, a generator may be able to raise the price for energy or ancillary services when there is inadequate grid capacity during peak load periods.

23. Several considerations must be carefully balanced by the CPUC in the design of the standby charge.

24. The rate design issues associated with distributed generation have a symbiotic relationship to each other, and to stranded costs.

25. The OIR and today's decision have not taken or adopted any steps which makes it easier to deploy distributed generation facilities.

26. Distribution competition is a broad term that encompasses various competitive alternatives to the present electric distribution system.

27. Further study and information gathering is needed for distribution competition.

28. A number of different California statutes authorize the publicly owned utilities to offer electric service.

29. Rule 15 of the UDCs' tariffs cover the extension of electric distribution lines to provide service to customers.

30. The steps that are detailed in § 783 can lead to a cumbersome and time-consuming process to change the line extension rules.

31. Master metering is a situation where a property owner receives all of its electrical energy through a single master meter.

32. Submetering is where the electricity supply flows to the master meter, which is then fed through the submeters to each tenant.

33. The CPUC has prohibited the resale of electricity by non-domestic customers through submetering since 1962.

34. The prohibition against submetering of commercial buildings was adopted long before a change to a competitive electric market was contemplated.

35. Section 381 requires the UDCs to collect from its customers a charge to fund certain public purpose programs, and § 385 places the same obligation on the publicly owned utilities.

36. The CPUC recognized in other decisions that programs such as energy efficiency and low income assistance programs would change in a competitive electric market.

37. The CPUC remains committed to programs which provide rate discounts to low income customers for their energy needs.

38. The future of the energy efficiency programs should be resolved in R.98-07-037, or in another appropriate forum.

39. Parties have raised concerns about the UDC's role in providing both monopoly and competitive retail services.

40. The UDC's role may be redefined depending upon what, if any, distribution services are ultimately unbundled, and what, if any, services end-use customers can choose.

41. The provider of last resort is the concept that a company has an obligation to serve all the customers in its service territory.

42. The default provider is the concept that the regulatory framework will designate an entity to serve a particular customer.

43. The UDC is the default provider of bundled electric services and electric distribution services.

44. The UDC's default provider role raises market power concerns because of the large number of customers they currently serve.

45. Electricity is a valued and necessary commodity that is of utmost importance to the safety, health, and welfare of the state's citizenry and economy, and should be provided to everyone at affordable rates.

46. No electric customer must be denied access to any of the components which constitute electric service due to the unwillingness of an electric distribution company to serve a particular geographic area or customer class.

47. It is too early to determine what social, economic, and labor impacts may result from distributed generation and distribution competition.

48. Some parties have suggested that an educational program for informing consumers about distributed generation should be pursued.

49. SDC requested in its opening comments that the CPUC investigate the alleged antitrust behavior of certain companies over the past fifteen years.

Conclusions of Law

1. The issues raised in this OIR should be bifurcated into two separate tracks, and handled in accordance with the procedures specified in this decision.

2. Since two new tracks have been created to address all of the issues raised by this OIR, this proceeding should be closed.

3. Since this proceeding is to be closed, the motions for evidentiary hearings filed by PG&E, and SDG&E and SoCalGas, are moot.

4. Section 218(a) provides that an end-user who generates electricity on its own property for its own use or the use of its tenants, and not for sale or transmission to others, is not considered an electrical corporation.

5. If the owner of a distributed generation facility sells electricity to others, and the sales fall within the exemptions contained in §§ 218 and 216(i), the owner of such a facility is not considered a regulated electrical corporation.

6. This decision does not prohibit the IOUs from participating in the installation, ownership, or operation of distributed generation on the customer-side of the meter at the present time.

7. At the present time, net metering is only mandated for wind and solar technologies of a certain size, and only benefits a set number of customer-generators.

8. The design of the new interconnection standards should adhere to the principles of a safe and reliable distribution system, that the standards be applied in a non-discriminatory manner, and that the standards be technology neutral.

9. SCE's tariff provision that prohibits a non-PURPA qualified generator from operating in parallel with SCE's system and taking standby service should be eliminated at the earliest opportunity.

10. The distribution system is to be owned and maintained by electrical corporations that are subject to the CPUC's jurisdiction.

11. Distributed generation facilities that are interconnected to the IOUs' electric distribution systems must meet the interconnection tariffs that have been approved by the CPUC.

12. In order to determine whether the provisions of CEQA apply, one must determine whether the contemplated activity is a project.

13. Since there is no project before us at the present time, the CEQA requirements do not apply to the present OIR.

14. The CPUC's policy on distribution competition shall look toward the currently applicable policy decisions and orders to resolve any distribution competition issues that may come before the CPUC.

15. It is unclear whether the Legislature intended to exempt a privately owned distribution system and generating facility from the CPUC's jurisdiction.

16. The natural gas issues that some parties commented upon should be raised in the appropriate gas proceedings.

17. SDC's request to investigate the alleged behavior of three companies in relationship to its involvement with photovoltaics, and the two related motions, should be denied because antitrust issues of the type that SDC alleges are beyond the jurisdiction of the CPUC.

18. The CPUC has no subject matter jurisdiction over the allegations contained in SDC's opening comments.

ORDER

1. The issues raised in this Order Instituting Rulemaking (OIR) shall be bifurcated into two tracks. The first track shall address the distributed generation issues identified in this decision. The second track shall address the distribution competition issues, and the role of the utility distribution companies (UDCs) in the retail electric market, as discussed in this decision.

2. The first track issues shall be addressed in a new rulemaking that is being issued today, R.99-10-025. The California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the Electricity Oversight Board (EOB) will work in a collaborative manner to resolve the issues in the first track.

3. The second track issues shall be addressed in a CPUC staff study and report as set forth below.

   a. The CPUC's Division of Strategic Planning (DSP) and Energy Division are directed to undertake a study of the distribution competition and role of the UDC issues identified in this decision, and to develop various proposals for how these issues should be addressed in the future, including recommendations for any legislative changes. DSP and the Energy Division may hold workshops, roundtables and other informal discussions in connection with this study.

b. The study regarding distribution competition and the role of the UDC shall be incorporated into a staff report. The report shall be submitted to the CPUC, the CEC, and the EOB no later than April 21, 2000. Copies of the report shall be served on the parties in the new distributed generation rulemaking, R.99-10-025.

4. If similar or identical issues are pending in other proceedings before the CPUC, and those issues have an impact on the distributed generation, distribution competition, or retail competition issues identified in this decision, the presiding officers assigned to those proceedings shall coordinate with the CPUC Commissioner assigned to the new rulemaking on distributed generation where the resolution of those issues are best handled.

5. Solar Development Cooperative's (SDC) request in its opening comments to this OIR that the CPUC undertake an investigation into the alleged anticompetitive behavior of three companies since 1984 with respect to photovoltaics is denied for the reasons stated in this decision.

a. Since the underlying allegations were contained in SDC's opening comments, and since this decision denies SDC's request that the CPUC investigate those allegations, the motions of SDC "To Allow Late Filing of Motion to Compel Discovery and Evidentiary Hearing," and the "Motion to Compell Discover (sic) and Evidentiary Hearing, are also denied.

6. Since all of the issues raised in this OIR have been bifurcated into two separate tracks, this proceeding is closed.

This order is effective today.

Dated October 21, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
JOEL Z. HYATT
CARL W. WOOD
Commissioners