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Decision 96-09-045 September 4, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority, Among Other Things, to Decrease Its Rates and Charges for Electric and Gas Service, and Increase Rates and Charges for Pipeline Expansion Service.	Application 94-12-005 (Filed December 9, 1994)
Commission Order Instituting Investigation into the rates, charges, service and practices of Pacific Gas and Electric Company.	I.95-02-015 (Filed February 22, 1995)

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O P I N I O N

This decision resolves certain preliminary matters in the portion of this investigation which addresses service and safety standards for the state's electric utilities. Specifically, this decision

- o Adopts reporting and recording requirements for electric utilities that cover: (a) system reliability using uniform methods for assessing data on the frequency and duration of system disturbances, (b) circuits that persistently perform poorly, and (c) accidents or incidents affecting reliability;
- o Denies the petition to modify Decision (D.) 95-09-073 filed by the Division of Ratepayer Advocates (DRA) seeking to expand the scope of this proceeding to include customer service practices of the gas utilities;
- o Denies the expansion of the scope of this proceeding to include areas of consumer protection that are outside the scope of the service and safety issues directly associated with reliability, and are more matters of general consumer service and relations not necessary or desirable to standardize across all electric utilities;
- o Continues the proceeding for purposes of issuing proposed standards on transmission and distribution system inspection, maintenance, and replacement cycles that will further define utilities' statutory obligation to provide high quality service and for receiving comment on those standards; and
- o Clarifies that the proceeding is not a ratemaking proceeding by (a) severing the investigation from PG&E's 1994 rate case, (b) combining the investigation with a new proceeding ordered for rulemaking, and (c) directing utilities to apply for

balanced reward and penalty ratemaking in other performance based ratemaking applications that will provide incentives for increasing the quality of service above the statutorily required level, or which will or improve aspects of service associated with general customer service and relations.

I. Background

In January and March 1995, severe storms hit northern California. During those storms, thousands of Pacific Gas and Electric Company (PG&E) customers experienced power outages and hazardous conditions. Hundreds of customers complained to the Commission of being unable to reach PG&E or receiving incorrect information from PG&E representatives. Others complained that unsafe conditions on PG&E's system went uncorrected for long periods during the storms and afterward. In response, the Commission initiated an investigation of PG&E's response to the storms and its readiness for them. Following hearings and briefs on these matters, we issued D.95-09-073. In that decision, we found that PG&E's employee reductions, extended maintenance cycles and an inadequate customer service telephone system had contributed to the problems on PG&E's system and with PG&E's storm response.

D.95-09-073 determined that the Commission's regulatory program failed to promote high quality service and safety and recognized that evolving competition in the electric industry may impose pressures on distribution utilities to compromise service. With those circumstances in mind, D.95-09-073 found,

> "...we believe we must establish uniform operational standards by which regulated utility performance may be evaluated. The standards should be specific and measurable and should apply to the electric distribution system maintenance operations and measure overall system reliability. We also intend to require the electric utilities to report major

or persistent service and safety problems, and to submit periodic reports on service reliability applying standard measures. We intend to adopt a uniform method for collecting and assessing data on the frequency and duration of system disturbances."

To accomplish these objectives, the decision initiated an investigation of reporting, reliability, maintenance, and inspection standards for all of the state's electric utilities. As part of that investigation, we directed the Commission Advisory and Compliance Division (CACD) to conduct workshops with the parties and to report on the progress of their discussions regarding related matters. On February 13, 1996, CACD issued that report. Among other things, the report recommends that the Commission:

> Direct the workshop participants to select up to fifteen "service indicators"[1] within a year which would be used to monitor utility service quality.
>
> Improve the content and timing of safety incident reports submitted by utilities to Commission staff, as proposed by the workshop participants;
>
> Adopt workshop participants' recommendations for how the Commission should measure system reliability;
>
> Require the utilities to submit "Preventive Maintenance Plans" which the Commission would review for consistency with Commission objectives regarding the provision of high quality, safe service. The plans would address inspections of and replacement criteria for equipment on electric distribution systems; and

1 Examples of "service indicators" would be percent of shut-offs due to utility error, percent of payments posted within one working day of receipt, and percent of calls receiving busy signals.

> Direct the utilities and invite others to establish a team to investigate definitions and customer expectations regarding power quality.

Several parties commented on the proposals in the CACD report, among them, PG&E, Southern California Edison Company (Edison), San Diego Gas & Electric (SDG&E), Toward Utility Rate Normalization (TURN), DRA, California Farm Bureau Federation (Farm Bureau), Sierra Pacific Power Company (Sierra Pacific), Southern California Gas Company (SoCalGas), William P. Adams, Coalition of California Utility Employees (CUE) and Advocates for Consumer Equity (ACE). Following receipt of the parties' comments on the CACD report, the Commission held a prehearing conference at which the parties discussed issues which required further resolution and those which were ready to be resolved by a Commission order. The assigned administrative law judge (ALJ) directed PG&E, Edison, SDG&E, Pacific Power and Light and Sierra Pacific to submit proposals for distribution maintenance and inspection standards no later than May 31, 1996. The ALJ also provided the parties an opportunity to file comments on issues raised in the workshop report. On April 22, 1996, Edison, PG&E, SDG&E, Sierra Pacific, SoCalGas, TURN, DRA, CUE, and ACE filed a final round of comments on issues addressed in this decision.

II. <u>Service and Safety Standards</u>

We begin with a general discussion of reliability, and outline both the traditional means of ensuring reliability and changes in the regulatory climate that are bringing changes. We think it is important to draw a distinction, as we did in D.95-09-073, between utilities' "statutory obligation to provide high quality service" (p. 18), and economic incentives that would encourage utilities to exceed those levels.

The notion that customers are entitled to reliable service is an essential aspect of the regulatory compact. Utilities with service territories have an obligation to serve all customers in that service territory and provide a societal necessity, in this instance electricity. Section 701 of the Public Utilities (PU) Code grants the Commission broad authority to supervise and regulate public utilities. Section 701.1(a) states:

> "The Legislature finds and declares that, in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity." (Emphasis added.)

The PU Code elsewhere does not refer to or define reliability. Further, Section 701.1(a) appears most germane to the planning of "resources," which is typically understood to refer to new generation rather than the distribution or transmission aspects of delivering that resource as "reliable energy services." However, the absence of specific reliability requirements for distribution or transmission is not remarkable as the codes have not been revised since changes in the industry have led us to consider each of the vertically integrated functions (transmission, distribution, and generation) in an unbundled manner. Section 701.1(a) is instructive in that it respects the direct relationship between cost and reliability, and provides for the exercise of discretion in balancing that relationship by stating that the goal of cost minimization is one subject to other constraints: reliability, environmental effects, and diversity of resources.

A review of the Commission's general orders reveals that the Commission has not further defined the meaning of "reliable service." Nor do the terms and conditions of tariffs, representing the obligation of utilities to customers, specify minimum reliability.

It is worth noting that reliability is a concept that attaches to each of the vertically integrated functions. Excluding for the moment the function of generation, the transmission and distribution system operate as a network from the perspective of retail customers, therefore a transmission contingency (loss of service) is as capable as a distribution contingency in being the cause of the end users' interruption in service. Recognizing that greater numbers of customers can be affected by losses in transmission, in instances of major outages utilities generally focus resources on restoring transmission, which returns to service many customers with unaffected distribution facilities, and then turn to distribution facilities. Because they are interconnected, transmission and distribution reliability are interrelated, and system-wide measures of reliability provide an indication of customer interruption, whether caused by distribution or transmission.

The Energy Policy Act of 1992 provided for increased access to utilities' transmission systems to wholesale customers. Naturally, concerns were raised that greater access could affect reliability. The legislature's response to this concern can be found in Section 211 of the Federal Power Act (16 U.S.C. 824(j)(b)):

> "RELIABILITY OF ELECTRIC SERVICE.--No order may be issued under this section or section 210 if, after giving consideration to consistently applied regional or national reliability standards, guidelines, or criteria, the Commission [FERC] finds that such order would unreasonably impair the continued reliability of electric systems affected by the order."

The consistently applied reliability standards referred to for California control area operators are those of the National Electric Reliability Council and its regional subgroup, the Western Systems Coordinating Council. These standards relate to the stability of the interconnected transmission systems of utilities in the region in that they specify the methods of operation that will be used in the event of major disturbances, and the degree to which neighboring utilities can lean on each other in non-emergency conditions. Without stability, an instantaneous concept, there would be, over time, no reliability, which is usually evaluated over longer time periods.

This Commission has similarly faced concerns that changes to the electric market it was considering would negatively affect the reliability of service. The Commission's answer to these objections - raised for nearly 20 years in response to any effort at competitive entry to the generation market - was to insist that reliability, and the cost of providing it, would continue to be a regulated monopoly. The independent system operator (ISO) is tasked with the obligation to provide reliable transmission service consistent with national and regional reliability criteria. (Restructuring Decision, pp. 32-33.) The operations and maintenance expenses necessary to support that service are expected to be included in the ISO's FERC set rates. The distribution companies are tasked with the obligation to continue to provide on a nondiscriminatory basis "quality distribution services" that do not "jeopardize service reliability or safety as it relates to distribution." (Id., p. 85.) Capital and expenses necessary to support this service are expected to be included in distribution companies state rates using performance based ratemaking. Generation system reliability is being addressed through other market mechanisms and interrelationships with the ISO for ancillary services that, while important, are beyond the scope of the issues in this proceeding and are under development in a FERC proceeding on the ISO.

Thus when it comes to important changes in the way transmission and distribution is used to provide reliable service, the federal standard prohibits FERC ordering transmission service that would "unreasonably" impair reliability of service, and this Commission's consistent but perhaps more stringent standard is that reliability will not be allowed to degrade from the level Californians have become accustomed to in the absence of electric industry restructuring. That level has, until recently, been fairly high. As of the end of 1991, no bulk power outage due to insufficient installed generating capacity had occurred for several decades. Over 90 percent of the service interruptions occurred within the distribution system, and the remainder were due to failures in the transmission system. Both types are affected by occurrences beyond a utility's control. California has experienced outages due to earthquake (1989 Loma Prieta, 1994 Northridge), severe "firestorms" (1991 Oakland, 1995 Los Angeles) and severely windy rainstorms (1995 PG&E storms). Safeguarding against these types of contingencies by building in added redundancy in the transmission and distribution systems beyond that needed when one necessary facility is affected (single contingency) is generally not reasonable due to the cost consequences and low probability of multiple contingencies.

However, matters of emergency preparation and responsiveness, as well as ongoing maintenance of the transmission and distribution system, have merited heightened attention and scrutiny to respond to public concern. Emergency preparation has long been an obligation of utilities. They have emergency preparation plans, cooperate with the California Utility Emergency Association and local emergency centers, are subject to directions from the Office of Emergency Services, and have generally provided mutual assistance. We see no reason to lessen these obligations, which we merely reiterate and clarify in this proceeding. It is appropriate for utilities to maintain with designated staff a copy of their current emergency preparation plans if they have not already provided them, and continue their practice of forwarding developing and timely information about an emergency response as it unfolds.

In non-emergency situations, we agree with DRA that regulatory oversight is more critical than ever for monopoly services, especially those offered by a utility that also offers services in competitive markets. We also agree with ACE that the Commission's goal should be to prevent problems from arising in the first place. As we have stated in other decisions, utilities facing competitive pressures in some of their markets may be tempted to reduce services to monopoly customers. We have subjected utilities to a revenue requirement cap as we make the transition to the restructured market, and this cap creates a tension between the goals of rate reductions on the one hand and completing the transition quickly on the other. We are mindful that reductions in revenue requirements associated with transmission and distribution might never be passed on to customers in the near term if the reduction is offset by accelerated payment of the competitive transition charge (CTC). For that reason, in setting PG&E's distribution operating and maintenance revenue requirement, we gave considerable weight to PG&E's testimony that reductions were reasonable, and that with respect to tree trimming the reductions were the result of increases in efficiency, not the result of reductions in maintenance that might manifest in lower quality service. (D.95-12-055, pp. 51-52.)

Uniform and measurable system standards are an important first step in defining reliability. They will help us fulfill our commitment to preserving reliability at levels that we have previously accepted as reasonable. (See, e.g., D.95-09-073 finding that, although problems affected PG&E's 1995 storm response, it was not unreasonable; p. 21; finding no. 14.) In the absence of any statute or Commission rule defining statutorily acceptable performance measures of reliability, and recognizing that reliability is strongly tied to costs, we refer to "statutory reliability" as those levels of reliability historically accepted as reasonable, as measured by indices then in use at the time. It is our goal to encourage improvement in this area.

As we have previously stated, general rate case incentive structures are unlikely to perform well in encouraging reliability above statutorily acceptable levels as competition grows, and may in fact encourage cost cutting that benefits shareholders at the expense of reliability. (D.95-09-073, pp. 14-16.) Therefore, utilities must pursue PBR that seeks to improve reliability.

The relationship between a minimum acceptable level of reliability that is based in statute, and encouragement through rewards of reliability above that level is clarified as follows: Standardized measures of reliability are readily enforceable through annual rate of return proceedings by reducing returns, as well as by investigations and orders to show cause initiated by particular events. Although system measures of reliability may give us these means for holding utilities accountable to measurable criteria, satisfaction of system measures (meeting historically reasonable levels) is not a shield that can stave off liability for damages in other forums or individual customer complaints in this forum. System measures may mask more localized problems, and the utility may still be found to have acted unreasonably with respect to maintenance or replacement of some portion of the system. Furthermore, meeting minimal system measures are not an adequate defense for failure to communicate with customers effectively during emergencies, or provide them through various media with information about the expected duration of the outage in their particular geographic area and the breadth of the outage. The public is entitled to this information when faced with broad outages to minimize the disruption to business and personal needs, particularly as personal needs for electricity can have health consequences. PBR incentives should align shareholder interests with reliability through PBR that encourages service above minimum requirements at a cost that is balanced with the value of the improvements. Over time, performance improvements brought about by PBR are likely to render Commission action for failure to meet minimum levels or reliability unnecessary.

A second step is initiated by combining this investigation with a rulemaking, and proceeding to propose rules for maintenance, inspection, and replacement cycles that represent industry practices. This step is consistent with the supplemental language in the Commission's budget:

> "On or before December 2, 1996, the Commission shall prepare and adopt specific, measurable, and enforceable standards for electric distribution system maintenance and operations to ensure system reliability and to minimize or prevent service interruptions due to storms, earthquakes, fires and brush clearing requirements, consistent with existing laws which ensure that the electric distribution system is protected from damage. (Item 8660.)[2]

A. <u>Reporting and Recording Requirements</u>

1. <u>Measures of Service Reliability</u>

D.95-09-073 states our intent to "adopt a uniform method for collecting and assessing data on the frequency and duration of system disturbances." Currently, there exists no common basis for assessing or reporting system reliability. Each utility uses several measures of system reliability and different types of information to compute the associated indices.

The workshop participants recommend the Commission require the utilities to report system reliability using common indices or measurements.

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2 This item also requires the Commission to set tree trimming and brush clearing requirements, which we are doing in a separate proceeding, and to ensure reliability is not compromised by competition, which our adoption of measurable and enforceable system reliability standards in this decision accomplishes.

System Average Interruption Duration Index (SAIDI). SAIDI is the average length of time customers were without power. It is calculated by dividing the total minutes of sustained customer interruptions by the total number of customers. It is typically calculated for a one-year period; for example, a SAIDI might be expressed as "100 minutes in 1995." A variation of this index, AIDI, may be calculated to identify the reliability of a region or circuit; for example, "84 minutes in Santa Barbara in 1995."

System Average Interruption Frequency Index (SAIFI). SAIFI is the average number of sustained power interruptions for each customer during a specified time period. It is calculated by dividing the total number of sustained customer interruptions by the total number of customers. It is typically calculated for a year. SAIFI may be calculated for region or circuit.

Momentary Average Interruption Frequency Index (MAIFI). MAIFI is the total number of momentary customer interruptions divided by the total number of customers. It differs from SAIFI by tracking only the frequency of momentary, rather than sustained, interruptions.

The workshop participants also recommend common criteria or definitions for calculating SAIFI, SAIDI and MAIFI which are included in Appendix A (items "a" through "j" from Workshop Report pages 81-83) and certain reporting standards, which are included in Appendix A (C.1.a, 2, 3, 4, 5; Workshop Report pages 83-86).

The workshops participants did not reach agreement on how the Commission should use the information on system reliability or what level of reliability would be considered unacceptable, nor was that required by D.95-09-073.

TURN and other workshop participants believe that applying the same standards across utilities is unwise because of geographic and weather-related differences between the utilities' systems. CUE recommends, however, that standards should apply a uniform methodology, as the workshop parties propose. TURN and CUB recommend that this proceeding, rather than individual performance-based ratemaking (PBR) proceedings, is the appropriate forum for developing reliability standards. TURN observes that PBRs are ratemaking proceedings rather than forums for determining the service criteria by which utilities should be judged.

Edison argues that the workshop participants' proposal for annual filings satisfies the Commission's stated interest in service reliability. SDG&E states that its system reliability has already been addressed in SDG&E's PBR.

We will adopt with minor changes the methods proposed by the workshop participants for measuring system reliability (Report, pp. 78-83, Sections B(1) and (2), as modified herein and appended to this decision as Appendix A) and direct the utilities to report these statistics (SAIDI, SAIFI, MAIFI) annually, as the workshop participants propose (Workshop Report pp. 83-86, Section C(1)(a) and (C)(2)). We concur in the requirement that utilities report information needed to calculate SAIDI, SAIFI, and MAIFI for the system (not by circuit). Reliability indices using a portion of the system (circuit, division, region, or district),[3] or smaller time periods (no smaller than a month) should be recorded and provided to any interested person upon request. With these requirements, we will either have the information we will need, or access to it, to monitor and respond to concerns about system reliability.

We modify two aspects of the indices relative to the Workshop Report because they would impair our ability to have useful and standardized measures of reliability. First, the

3 Utilities should record information at whichever of these levels (circuit, district, division, or region) their then current information collecting capacities exist at. We recognize that all electric utilities are not similarly situated with respect to how this type of information is collected or maintained.

parties have proposed that each utility may exercise its discretion to exclude events it believes appropriate. (Workshop Report, p. 81.) We will permit exclusion of events only if they are caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government. In the absence of a state of emergency being declared, any other natural disaster may be excluded only if it affects more than 15% of the system facilities or 10% of the customers, whichever is less for each event. No other events should be excluded from the standardized measure of these indices that must be reported, although utilities are free to include or exclude any event they like and record and calculate different results for other purposes.

We intentionally eliminate the subjectivity that would result by excluding all outages caused by any event outside of utilities' control, as that would render the results less useful. Reliability should not merely be a measure that reflects the fictional happenstance of a world without any disturbance. It should reflect the actual responsiveness of the utility in addressing disturbances. For example, were we to permit ad hoc exclusion of outages caused by a car knocking down a pole, we would collect no useful information about the duration of these types of outages, which is a useful indication of the utilities' ability to correct that outage. A strongly quantitative measure of performance is not compatible with permitting utility discretion in excludable major events, and does not impede our ability to understand explanatory information about those events or their impact on the indices.

Second, Edison proposed that the end of an outage be measured differently: when only one distribution transformer remains out of service rather than when all customers have power restored. (Workshop Report, p. 81, n. 18.) We disagree that the effect is "insignificant." It impairs our ability to have uniform standards and measures, and would over time tend to suggest

Edison's outages are not as long as other utilities because customers may not have power restored even if only one distribution transformer is out of service. We are not persuaded that Edison has sufficiently different limitations on its information collecting abilities to justify this difference.

Other measures of reliability may be useful to utilities for comparative purposes, for PBR implementation, or for other internal management tasks, and we do not preclude the use of other measures. In fact, continuing to use prior methods would be helpful for the next 3 years. We fully appreciate that because each utility now has different methods for calculating these indices, and has used ad hoc discretion to include or exclude events beyond their control, that the new indices will necessarily be of little value until experience is gained with them. But we must begin at some point in time to standardize these measures if we are to monitor and correct deterioration in reliability. Similar transitions are inherent in many other standards. For example, when the Bureau of Labor Statistics changes the way it measures inventory, economists understand that, for some time, changes in actual inventory become masked by the change in measurement methodology. Because the same data is used, utilities should continue to calculate indices as they have in the past for at least three years, which should assist our understanding of changes in the index caused by reliability and those caused by setting new standards for calculating the index. We state for purposes of guidance to the parties that it would be extremely unlikely we could, given the limited experience with the new indices, order a reduction in return levels before we have at least three years of experience with them. Parties advocating this result will have a heavy burden to persuade us that, given a longer historical trend, reliability has significantly fallen and fails to meet levels previously deemed reasonable. Utilities should make a good faith effort to normalize reliability data over the last ten years consistent with the standards we adopt here, but this exercise has inherent limitations that render the result of questionable evidentiary weight. Those efforts should therefore not become an undue focus and burden to parties.

We also recognize that the Commission's informational needs to ensure a statutorily mandated quality of service deviate from other uses of reliability information like performance based ratemaking. We concur with the Workshop Report (p. 87, Section (C)(5)) that SDG&B should continue to use the methods previously developed for its PBR, and that other utilities may propose PBR mechanisms that use either these or other means of measuring reliability. Utilities should seek to align incentives in suggesting balanced reward and penalty ratemaking in other ratemaking proceedings that will improve system reliability beyond statutorily acceptable levels.

2. <u>Circuits that Persistently Perform Poorly</u>

TURN proposes that the utilities provide data every two years on individual circuits which are characterized by poor performance. TURN proposes that the utilities report circuits that experience SAIDI in the worst quintile for three years in a row.[4] TURN proposes to control for rural circuits, which do not perform as well as those in more populated areas, by emphasizing the performance on circuits serving an above average number of customers.

Farm Bureau, CUE, and DRA make similar points, arguing that if the utilities' systems have problem circuits, the circuits

4 TURN states there is an .8% chance that a circuit would randomly appear in the worst quintile for three years. Otherwise a circuit could appear to perform poorly because its repair would not be cost-effective or the utility is not exploring solutions adequately.

should be identified and repaired. Hiding problem circuits in average measures of system reliability erodes utility accountability, according to DRA, and provides no benefit to any party except utility managers who wish to avoid the inconvenience of public disclosure. Farm Bureau argues that rural customers have a right to know what level of service is provided to them and are capable of appreciating legitimate reasons for differences.

SDG&E argues that its PBR mechanism provides adequate incentives for assuring reliable service because it is liable for up to $4 million for inadequate service reliability. It comments that TURN has not presented any customer complaints regarding poorly performing circuits. It also observes that presenting information about the worst circuits provides no incentive for the utilities to improve circuit performance because there will always be poorly performing circuits relative to the remainder of the utility system.

PG&E argues that the Commission should not require utilities to provide statistics on poorly performing circuits. It observes that some circuits will perform worse than others, such as those in mountainous areas, and that requiring their identification implies that all circuits should perform at the same level. It argues that if an individual circuit is performing poorly, it should be determined and remedied through a Commission investigation, "not through an inquisition by the local media."

We agree with CUE, TURN, and DRA that the utilities should be required to identify poorly performing circuits in Commission reports. We also agree that there will always be a worst quartile relative to the remainder of the system. Information about those circuits is not the type of information we intended to collect. Rather, we are concerned with groups of customers being served on a common cluster of distribution facilities that experience repeated disruption and inform us of their difficulty in arranging for the necessary repair or maintenance work. We wish to spotlight such clusters of customers in a manner that orients the utilities' work and consolidates customer complaint information in a meaningful fashion. For example, customers in a common neighborhood, served from a common distribution feeder, who have experienced on average an outage over 5 minutes on a monthly basis over any annual period are suffering from a typically poor system reliability, are complaining directly to the Commission about difficulties obtaining repair work, and may simply be falling through the cracks. A recording and reporting requirement should consolidate this type of information over time, assist the utility in prioritizing work, and allow us to intervene and mandate remediation on a broad basis if the reporting becomes extensive and repetitively identifies the same clustered areas.

Requiring the utilities to report statistics on poorly performing circuits does not imply that all circuits must perform equally. We suspect public disclosure will motivate utility repairs with limited regulatory intervention. Although the utilities may not like the public attention they may receive from disclosure of information regarding circuit performance, we will not hide information from the media or the general public on the basis that the utilities might be inconvenienced by any public attention it draws.

Having asked the parties to collaborate on a definition of "poorly performing" circuits and received no useful recommendations, we will for the time being define those circuits we wish to receive publicly filed information about along the lines indicated above. Customer service representatives must relay information that will allow utilities to track service quality complaints in a manner that allows the utility to determine whether and when, on a rolling annual basis, customers commonly served below the level of the last step-down transformer in the area are experiencing more than one 5 (or more) minute outage per month on average, excluding major events brought on by natural disasters (fire, earthquake, wind and rain storms) that affect 15% or more of the entire system.

Although we recognize fully the burden associated with this requirement, pockets of circuits that perform this poorly simply should not exist in the first place and should not be falling through the cracks if they do exist due to the failure to intelligently track distribution system performance. We would have preferred to tailor this definition to the information utilities already do or should collect from customer service representatives for purposes of planning and allocating resources on distribution maintenance. However, having received no useful information through the workshop process, this definition of poor performance will have to suffice unless and until utilities jointly file for a petition to modify this decision and submit a uniform definition that accomplishes the same purpose with no substantial loss in disclosure. Such a petition, if filed, is exempt from the requirements that good cause be shown for filing in less than a year from this decision, and we would determine at that time whether hearings on the proposal were desirable. Such a petition will not be exempt should utilities file for a standard that is not the same for each of them, as part of our objective is to have comparable information to assist our understanding of performance. We commend to the utilities this goal.

3. Accidents or Incidents Affecting Reliability

Currently, some utilities report accidents or incidents pursuant to criteria established by its Utilities Safety Branch (USB). We understood that utilities sometimes took the position, upon staff investigation, that there was no requirement that reports be filed for incidents involving personal injury or property damage, or that there was no specific time frame or guidelines that applied. (D.95-09-073, p. 17, n. 7.) The utilities generally have informed USB of accidents which involve utility-owned electric facilities that result in fatalities or injuries serious enough to require hospitalization. Some utilities have adopted the practice of informing USB of such accidents by telephone within one business day of their occurrence, and submitting associated written reports within 30 days. Others have reported only when USB inquires, and we have concerns associated with the related difficulty of these investigations due to the lack of any systematic record keeping associated with these events.

The workshop participants propose changing the existing criteria and notification procedures. Specifically, the parties propose that the utilities report all incidents involving electric facilities which meet one or more of the following criteria:

1. The incident results in a fatality or injury requiring in-patient hospitalization;
2. The incident has attracted significant public attention or has received significant news media coverage; and
3. The incident causes estimated property damage of $20,000 or more.

The parties propose the following notification procedure:

The utility shall report incidents and accidents no later than two hours after the utility has determined that the incident is reportable under criterion (1) or (2) above. The utility shall make the call to the Commission's Incident Reporting telephone number. If the caller receives a recording, the utility shall leave a message on the recorder stating:

a. Time and date of incident;

b. Time and date of the call;

c. Location of the incident;

d. A detailed description of the accident which includes information about fatalities, injuries, facilities and third-party property damage; and

e. The name and telephone number of a utility employee who may be contacted about the accident.

When this information is submitted by telephone, the utility shall also submit a report by facsimile using a standard reporting form no later than the end of the subsequent working day. During normal business hours, utilities may submit the information by facsimile using a standard reporting form. The utilities may use other means of communication technology, such as electronic mail, with the concurrence of USB for an agreed upon Incident Reporting receipt address that is stable over time.

The utilities must also submit written reports within 30 days for accidents meeting criteria (1) or (2) above. The reports are due within 60 days for accidents meeting criteria (3) above.

No party opposes adoption of the workshop participants' recommendations. The proposals appear to improve existing practice by requiring the utilities to provide better and more timely information. We will adopt the reporting recommendations of the workshop participants. In light of past discrepancies of opinion regarding whether incident reporting was a mutual accommodation and practice of utilities that could be altered by them without notice or decision, we emphasize the following points: (1) reporting requirements are not a utility practice that is discretionary on the part of the utility, but are a regulatory requirement for which failure to consistently comply will be sanctionable, and (2) satisfaction of reporting requirements is not a shield against further USB investigation, or a substitute for reasonable record keeping practices. We encourage USB to discuss with each utility their existing record keeping for incidents, and attempt to ensure such records are appropriately centralized and complete for USB's purposes. We do not adopt any particular mandatory recording requirements at this time.

B. Distribution System Inspection, Maintenance, and Replacement Cycles

D.95-09-073 ordered that the investigation provide the Commission with a forum for considering "appropriate inspection, maintenance, and replacement cycles for overhead and underground distribution plant." (Ordering para. 2.) In response, the workshop participants proposed that the utilities submit "Preventive Maintenance Plans" to the Commission which would set forth the utilities' programs for inspecting and replacing equipment on their electric distribution systems. Workshop participants appear to propose general plans which would not apparently be binding on the utilities or considered to be Commission rules. The utilities propose to submit the plans to the Commission staff informally, confidentially and without formal Commission review or approval. CUE contends that accountability is jeopardized if the standards by which the utilities will be judged are not debated, approved by a Commission order and made public.

The ALJ subsequently addressed this recommendation in a prehearing conference, stating that the parties' joint proposal for the utilities to submit such plans would not satisfy Ordering Paragraph 2 in D.95-09-073 in that it failed to provide for the objective of holding utilities accountable for distribution maintenance according to measurable criteria and performance standards. The ALJ directed the electric utilities to submit proposals for standards which the Commission would address in a subsequent decision and after the parties have had an opportunity to comment. The utilities filed their various Maintenance Plans on May 31, 1996, which they propose to be unenforceable and not standardized.

We consider the submission of Preventative Maintenance Plans in compliance with the plain language of ordering paragraph that <u>measures</u> of system reliability should be standardized, but that inspection, maintenance, and replacement cycles should be "appropriate." The distinction is drawn due to a variety of factors that complicate standardization of a maintenance plan down to the lowest level of plant. Utilities have distribution plant that covers a variety of geographical and climatic conditions in California, and is therefore subject to significant diversity of wear and aging. For example, wood poles in downtown San Francisco simply experience different wear than poles in the Mohave desert or more rugged Sierra terrain. Additionally, urban settings render some equipment easier to access, and disruption is more likely to have consequences for public safety or traffic congestion. These distinctions do not imply that rural customers should suffer degraded service. It merely respects that cycles of inspection, maintenance, and replacement have important variances based on the types of equipment, its location and accessibility, and the weather and loads it is subjected to. Hence these cycles should be "appropriate," not uniform. The submission of Preventative Maintenance Plans is a step in the right direction. Providing them under seal is not, as it frustrates a very keen and growing public interest and concern with the reliability of the system and the potential negative effects of competition in generation.

III. Scope of the Proceeding

A. Customer Service Standards

The Workshop Report states that the participants discussed certain standards for customer service such as billing practices, call center processing, and responsiveness to service orders. CACD directed workshops in this area on its own initiative with the support of DRA and TURN. The utilities participated actively in the workshops but do not support continued work in this area.

DRA and TURN believe that, notwithstanding the scope of D.95-09-073, the Commission should continue the efforts already begun on subjects related to customer service. In its comments, ACE proposes the Commission proceed to develop a general order that defines consumers' rights, requires the utilities to provide consumers with good information and establishes remedies in cases where service and safety problems arise. ACE comments that current consumer complaint procedures are inadequate at the utility facilities and the Commission's Consumer Affairs Branch.

PG&E, Edison, SDG&E, and SoCalGas argue that customer service standards are outside the scope of this proceeding. Edison proposes related issues be addressed in PBR proceedings. SoCalGas states it has proposed customer service standards in its PBR. PG&E comments that the electric restructuring proceeding is considering customer service issues. It refers to a workshop report to be submitted by October 1996 which will address the Commission's role in providing customer protection, and may lead to the development of changes in utilities' tariffs with respect to customer service.

Edison proposes that its "Service Guarantee" program addresses customer service issues. That program offers a $50 credit on a customer's bill if Edison fails to install meters on the committed date, respond to service disruptions within four hours of notification, or restore service within 24 hours of a service disruption. The "Service Guarantee" program surely indicates a commitment on Edison's part to good service. It is, however, a voluntary program using Edison's determination of what constitutes good service, not the Commission's.

CACD's report recommends that the Commission follow a proposal by several parties to adopt customer service standards following a period of study.

D.95-09-073 did not require the development of customer service standards of this nature, or authorize an investigation into customer service practices. Ordering Paragraph 2 set forth this proceeding as the procedural forum for "specific service and safety standards."

> As part of this investigation, the Commission will consider appropriate reporting arrangements, standardized measures of system reliability, and appropriate inspection, maintenance, and replacement cycles for overhead and underground distribution plant. (D.95-09-073, p. 24.)

The Commission was very clear which aspects of "service," a word that is otherwise comprehensive enough to touch upon every aspect of the utilities' business that relates to a customer, were to be included in this investigation. A review of the decision at pages 17-19 further elucidates Ordering Paragraph 2, by explaining what the Commission means by "reporting" ("service reliability applying standard measures," and "major or persistent service and safety problems"). Service in this context, where we were focused upon the concerns raised by PG&E's response to outages in January and March of 1995, referred to interruptions in the delivery of electricity, not every aspect of consumer relations. Although we were reluctant to interfere with a consensus building effort that went beyond our order, consensus has not emerged and no further expansion of this proceeding is warranted for the following reasons.

First, we acknowledge that the assigned commissioner ruling of March 28, 1995 identified as a specific issue "customer access to customer service employees" following an emergency. For that reason, we imposed call center requirements upon PG&E in D.95-09-073 of an interim nature. We were concerned that, with the implementation of a new customer service phone system, customers' ability to contact the utility during wide-spread outages had been lessened. However, this concern is one driven by an extraordinary event; outages were sustained by 1.4 million customers in one instance, and 1.3 million in another. Unlike PG&E, we have not received reports of consumer frustration with access to (or attitude of) customer service representatives of Edison or SDG&E. We are not confident that the interim standards PG&E is subject to are either cost effective, or capable of being met during major system-wide disturbances, and they are most definitely not a substitute for effective use of media in communicating with the public during broad outages about the condition of the system, or how long outages may last. We need more experience with these interim call center standards, and we will review that experience in conjunction with the rate consequences when we set performance based rates for PG&E's distribution functions.

Second, although the scope of the customer service issues in the Workshop Report have served an important function of educating us about the range of monopoly functions now embraced in tariffs, and how general those tariffs are in relation to modern concerns regarding service, the scope of these issues is broader than the service reliability issues that are the focus of this proceeding. They are in part congruent with other activities before the Commission, which would have been impossible for the parties to anticipate in September 1995. In December 1995, we issued our Electric Restructuring Decision (D.95-12-063, as modified by D.96-01-009), outlining consumer protection issues. The Roadmap Decision (D.96-03-022) further addressed consumer protection and requires a workshop report in October. The Restructuring Decision focused upon consumer information in discussing consumer protection (pp. 187-188), but the Commission has also made a general commitment to retaining high-quality service in monopolistic markets (p. 85). Billing services, call center operations, and the utility's responsiveness to service orders are among the types of customer services related to the electric distribution system that we intend to continue to oversee even as generation becomes competitive. We want to ensure that utilities "continue to provide quality distribution services" (id.) that do not discriminate against direct access customers in their service territories. This commitment's reference point is existing service quality and its nondiscriminatory character.

Because there are rate consequences flowing from the level and quality of service associated with billing, call centers, and responsiveness to service orders, efforts to elevate the quality of these services above existing levels belong in performance based ratemaking cases affecting revenue requirement for related labor, phone, and other communication systems (i.e., distribution rates). We fully expect that utilities will seek to enhance their reputations for quality distribution services as competition increases, because that interaction with the customer is important and affects customers' attitudes about competitively provided services. Each will endeavor in certain instances involving customer location decisions to stand out as superior. We intend to insure that these improvements in distribution service are made on a nondiscriminatory basis, and that all customers benefit, not just those viewed as important for continued generation service. Edison's voluntary program, funded by shareholders, is the type of activity we are reluctant to standardize through tariffs applicable to all electric utilities, and is the type of innovation fostered by utility-specific PBR, encouraged by the greater consumer attention upon all aspects of service that competition brings.

By declining to expand this proceeding, we are reaffirming D.95-09-073 in that we choose PBR as the appropriate forum for addressing economic incentives for utilities to provide high quality service above and beyond that statutorily required. (D.95-09-073, pp. 18-19.) Existing billing, call center, and service responsiveness provided by utilities has not been determined unreasonable upon any record and generally meets, as it has for many years, the statutory obligation to provide reliable energy services at minimum cost. Specific instances of failure to meet this obligation are remedied through the informal consumer assistance functions of the Commission, which help thousands of customers, and formal functions like expedited and regular complaints. We have often discussed the potential for PBR to provide a greater alignment of ratepayer and shareholder incentives, and customer services of this type are no exception. Improvements in the quality of service are entirely plausible and thoroughly encouraged through balanced reward and penalty ratemaking mechanisms.

B. Remedies for Failure to Comply with Standards

TURN proposes that the Commission adopt in this proceeding specific penalties for a utility's failure to comply with maintenance standards. The utilities observe that state and federal laws already subject them to fines and penalties for failure to comply with Commission service and safety standards. They recommend additional remedies be considered in other proceedings if at all.

Maintenance cycles, as discussed above, should be "appropriate," and that word invokes a degree of non-uniform discretion and flexibility that does not readily lend itself to compliance determinations and sanctions. We will reconsider TURN's position when we adopt rules that will be proposed and subject to comment later this year. In contrast, development of uniform measures of system reliability (not maintenance) assist the Commission in monitoring unacceptable performance and comparing utilities, and we have sufficient statutory authority through rate of return reductions and orders to show cause that will penalize utilities that significantly reduce reliability. We intend to use this authority to enforce a measurable reliability standard that is no less than previously determined reasonable levels.

C. Natural Gas Utility Customer Service Standards

On November 28, 1995, DRA filed a petition for modification of D.95-09-073 proposing that the Commission extend the customer service portion of the investigation to jurisdictional gas utilities, SoCalGas and Southwest Gas Company (Southwest). DRA believes that fairness and efficient use of the parties' resources dictate that any standards adopted for the electric utilities apply equally to gas utilities. DRA observes that the gas utilities have already participated in relevant workshops in this proceeding.

SoCalGas opposes DRA's petition, observing that it has proposed a set of customer service standards in its PBR application filed June 1995. In that proceeding, SoCalGas proposes an incentive mechanism based on broad measures of customer satisfaction. SoCalGas observes that this proceeding resulted from complaints relating to PG&E's electric service, and that such complaints have not been received for gas service. It observes that gas outages are rare.

As we stated previously in this order, PBR mechanisms such as those proposed by SoCalGas which provide ratemaking incentives based on broad measures of customer satisfaction are not a substitute for service and safety standards that would apply equally to all customers. Nevertheless, SoCalGas is correct that our inquiry here evolved from a series of problems that were identified for an electric utility. We believe these problems arise in the context of anticipated industry changes which would expose electric utilities to competition. The gas industry has been undergoing such changes for many years and we have not received the types or number of complaints for the gas utilities. This is not a finding that the gas utilities' customer service tariff provisions or practices should not be subject to some type of review. At this point, however, we believe the focus of our attention should be on electric utility activities. If we become aware that SoCalGas and Southwest customers are not receiving the highest quality service, we will initiate an inquiry of their customer services.

Accordingly, we will deny DRA's petition to modify D.95-09-073.

D. Transmission System and Distribution Substations

The workshop report identifies DRA's recommendation that the scope of this inquiry be expanded to include transmission system and substation maintenance and inspection standards. In its comments, DRA points out that these portions of the electrical system should be part of any regulatory program aimed at promoting service and safety.

PG&E and Edison believe there is no need to consider standards for transmission and substation facilities. Edison observes that only about 20% of service interruptions are attributable to transmission and substations. PG&E refers to D.95-12-063 which suggests that only those facilities "downstream" of the Independent System Operator would be subject to state regulation and that the remainder would be subject to federal jurisdiction. SDG&E also believes that the development of transmission standards would be a complex and time-consuming effort without any evidence of need or offsetting benefits. Sierra Pacific makes similar comments.

SDG&E observes that the Federal Energy Regulatory Commission (FERC) and this Commission will need to distinguish distribution system from transmission systems for jurisdictional reasons.

DRA believes that maintenance of the transmission system is essential to the safe operation of the system as a whole, as highlighted by the extent of transmission damage during the 1995 storms. DRA also argues that distribution substations should be considered within the scope of this proceeding because they are part of the distribution system. In general, DRA observes that the transmission system and distribution substations are not distinguished from the distribution system in any way that would obviate the need for Commission oversight. CUE also recommends including transmission equipment and distribution substations as part of this inquiry.

As SDG&E states, the FERC and this Commission are in the process of defining distribution and transmission systems for purposes of establishing jurisdictional responsibilities and regulatory programs. We agree with DRA that the Commission should consider appropriate standards and reliability factors, and believe that system-wide measures of reliability are an important first step in this direction. Although we may defer to the FERC on transmission ratesetting, we are within our jurisdiction to establish benchmarks for utility performance affecting end users whether they depend upon operation of the distribution system, the transmission system, or both. We may propose further standards if we find that enforcement using system-wide measures and PBR mechanisms fail to preserve and improve existing reliability levels.

IV. Confidentiality of Service and Safety Information

The workshop report highlights a controversy about whether information provided to the Commission regarding service should be held confidential. Such information is and always has been available to the public. The utilities advocate confidentiality of all future submittals on the basis that disclosure may compromise their competitive positions.

In the workshop report, CACD recommends that the Commission reject any proposals to hold service information confidential on a routine basis. Instead, it recommends that the Commission use its discretion under Section 583 to require full disclosure of utility information about customer service, safety, system reliability, and inspections and maintenance.

DRA comments that service and safety program elements must be accessible to the public, consistent with Commission objectives outlined in the Commission's Vision 2000 report. DRA observes that the information which is the subject of this proceeding will not compromise the utilities' competitive positions, as the utilities charge, because the information concerns utility activities and services that are not competitive.

The Commission has an obligation to regulate monopolistic elements of the utility system, and utilities' argument that the information could place them at a competitive disadvantage fails to distinguish that competition is primarily in generation, not in the provision of monopoly distribution services. The concerns raised in this investigation are related to those elements of the utilities' electric systems which are monopolistic. The utilities have not convinced us that public disclosure of standards and performance of the distribution system will compromise their competitive positions. To the contrary, public disclosure of such information will promote high-quality service and safety. We decline to accede to the utilities' proposal to provide a blanket prohibition on public disclosure of information we require they report. With the exception of the type of information provided in accident or incident reports that is currently submitted under seal, all other information required by this decision to be submitted to the Commission will be public until and unless the Commission finds to the contrary. The utilities have a burden to show that any information we require be reported by this decision should be confidential for reasons other than generalized competitive disadvantage and on an item-by-item basis, should they seek such a finding.

V. <u>Next Procedural Steps</u>

Our discussion above respects the relationship of costs to reliability, and clarifies that this is not the forum for ratemaking that will improve service above statutorily acceptable minimum levels. In acknowledging the reasonableness of past reliability, we act consistently with prior determinations of reasonable costs for all electric utilities' current and related revenue requirements. Consequently, this investigation should be severed from the rate application that it derived from.

Additionally, we are at this time unpersuaded that the submitted Maintenance Plans are as far as we should attempt to go in setting rules for maintenance, inspection, and replacement cycles of distribution facilities. Therefore, we will use the Maintenance Plans and industry standards to propose rules that set forth specific standards. We leave for comment on those proposed rules: (1) whether the specific standards we propose for maintenance, inspection and replacement cycles should be enforceable and subject to penalty for noncompliance above and beyond any penalties for failure to meet system-wide measures of reliability, and (2) whether the specific standards we propose, if enforceable, present any perverse incentives to needlessly incur costs for facilities that, based on their condition, are still service worthy. We initiate a rulemaking proceeding, consolidated with our investigation, for potential adoption of rules.

<u>Findings of Fact</u>

1. D.95-09-073 stated the Commission's intent to investigate appropriate reporting arrangements, standardized measures of system reliability, and appropriate inspection, maintenance, and replacement cycles for overhead and underground distribution plant.

2. Pursuant to D.95-09-073, CACD held workshops on electric utility service and safety and submitted a report on February 13, 1996 summarizing the discussions at the workshops. Several parties subsequently filed comments on CACD's report.

3. The workshop participants propose that the utilities be required to submit "Preventive Maintenance Plans" to the Commission staff. The utilities propose that the plans be submitted confidentially and that they be subject to modification at the utilities' discretion.

4. The workshop participants jointly propose the adoption of a variety of common measures of service reliability as set forth on pages 78-83 of the Workshop Report.

5. PBR mechanisms provide certain financial incentives for utility management to improve reliability above historical and reasonable minimum levels, but would not provide us with any assistance in enforcing a minimum level of acceptable reliability.

6. Requiring the utilities to report on individual poorly performing circuits may motivate utility repairs with limited regulatory intervention and does not imply that all circuits must perform equally well.

7. The workshop parties proposed several improvements to the electric utilities' requirements for reporting safety incidents.

8. D.95-09-073 (Ordering Paragraph 2) did not include in the scope of the investigation the subject matter of "Customer Service" (listed in the Workshop Report, II), natural gas, or transmission.

9. The Commission and FERC are in the process of defining distribution and transmission systems.

10. The portions of the electric system which are subjects of this investigation are for the provision of service that is monopolistic in character, likely to remain monopolistic for the foreseeable future, and requires protection from the pressures of competition in the generation sector.

11. The utilities have not demonstrated that public disclosure of service and safety standards and associated performance statistics will compromise their competitive positions.

12. Unlike PG&E, SCE and SDG&E do not generate an unacceptable level of complaints to the Commission about frustrated access to and attitude of customer service representatives.

13. Reliability has an associated cost.

14. Utilities have an obligation under statute to provide reliable electric service at minimal cost.

15. A minimum level of acceptable reliability for statutory purposes is the level that has historically been found reasonable as measured by the indices in use at the time by each utility.

16. System-wide measures of reliability provide an indication of customer interruption in service, whether caused by distribution, transmission, or both.

17. Federal law does not allow increased wholesale transmission access to impair reliability, taking into consideration the regional or national reliability standards, guidelines, or criteria as consistently applied.

18. The Western Systems Coordinating Council is the source of reliability criteria consistently applied to control area operators in California.

19. Building a transmission or distribution system to sustain improbable losses of more than one facility is generally not reasonable.

20. Although building an electrical system to preclude all outages is, if possible, not reasonable in cost, utilities nevertheless have a duty to have emergency preparedness plans, including plans to inform the public through various media about the expected duration of the outage in their particular area as well as the breadth of the outages, and respond reasonably to service restoration in deployment of available or attainable resources.

21. SAIDI, SAIFI, and MAIFI are useful reliability indices if uniform methods for collecting and assessing data on the frequency and duration of system disturbances is collected.

22. Discretionary exclusion of system disturbances from the reliability indices compromises their quantitative strength as performance indicators.

23. The duration of outages should be measured the same for all electric utilities, and Edison has not provided information

indicating it is unable to measure the length of the outage as other utilities do.

24. The existence of standardized reliability indices does not impair utilities' ability to collect any data they find useful for comparative purposes, PBR implementation, or internal management functions.

25. Parties have provided no useful criteria for defining circuits that persistently perform poorly.

26. The portion of circuits that is in the last quartile of performance using the reliability indices are not necessarily performing poorly.

27. Reasonably responsive and cost conscious businesses use customer information to direct their maintenance resources.

28. The Commission has an established practice of accepting accident reports under seal.

29. Standard criteria for reporting accidents and incidents will keep the Commission informed enough to take action if it appears corrective measures are appropriate. The Commission's established procedural practice is to initiate a duly noticed order to show cause and investigation following a staff recommendation and report on an accident or incident.

30. The submission of Preventative Maintenance Plans allows us to review appropriate inspection, maintenance, and replacement cycles for distribution facilities.

31. Cycles of inspection, maintenance, and replacement have important variances based on the types of equipment, its location and accessibility, and the weather and loads it is subjected to.

32. Customer service issues are closely related to customer protection standards necessary for electric industry restructuring.

33. The public interest in nondiscriminatory customer service for distribution functions, including billing, call center, and service responsiveness under non-emergency conditions, is not

in conflict with individual utility efforts and innovations that elevate the quality of these services.

Conclusions of Law

1. The Commission should adopt the uniform standards for measuring reliability and identifying circuits that repeatedly perform poorly that are in Appendix A.

2. Respondent utilities shall record and maintain reliability information specified in Appendix A and provide it to any interested person within 30 days of a request.

3. Respondent utilities should have emergency preparedness plans maintained with the Commission, cooperate with emergency coordination associations, and provide mutual assistance to each other in the event of emergencies defined as excludable major events for purposes of measuring reliability.

4. The Commission should propose rules for the inspection, maintenance, and replacement of distribution facilities identified in utilities' Maintenance Plans that are flexible and reflect industry standards.

5. The Commission should adopt the reporting requirements for safety incidents proposed by the workshop participants in this proceeding, as set forth in Appendix A.

6. The Commission should deny DRA's petition to modify D.95-09-073 seeking to expand the scope of this investigation to SoCalGas and Southwest Gas.

7. The Commission should address the rate consequences of reliability in rate proceedings.

8. The Commission should address consumer service issues, including billing, call centers, and response time in non-emergency conditions in rate proceedings.

9. Respondent utilities should propose performance based ratemaking that addresses system-wide reliability and the six most frequently requested customer services by January 1, 1998.

10. With the exception of accident reports, all information provided by the utilities pursuant to this investigation should be made public absent a finding on a case-by-case basis that public disclosure of such information will compromise a specific aspect of utility competitiveness.

O R D E R

IT IS ORDERED that:

1. Respondent electric utilities shall submit information on system reliability on January 30 of every year beginning January 30, 1997, using the indices developed by the workshop participants in this proceeding, as set forth in Appendix A, pages 78-83.

2. The reporting requirements for safety incidents as set forth in Appendix A are adopted.

3. Division of Ratepayer Advocates' petition to modify Decision 95-09-073 seeking to expand the scope of this investigation to Southern California Gas Company and Southwest Gas is denied.

4. Respondent electric utilities shall provide to any interested person within 30 days information required in Appendix A to be recorded and maintained.

5. The assigned administrative law judge shall with the assistance of staff or consultants prepare by November 6, 1996, proposed rules that reflect broadly accepted industry practice for the cycles of inspection, maintenance, and replacement of major distribution facilities identified in the Maintenance Plans of respondent electric utilities. Cycles proposed in the Maintenance Plans should be taken into consideration, but are not to limit proposed rules. Proposed rules shall not address tree trimming, brush or foliage clearances, as those rules are under development in another proceeding. Proposed rules shall be flexible in that

specified cycles are to be stated in terms of inspection, maintenance, and replacement that is "no later than" a defining time period that represents the maximum duration acceptable under industry practices. Proposed rules need not address every component of the distribution system.

6. All information provided by the utilities pursuant to this investigation, with the exception of accident reports, shall be made public absent a finding that public disclosure of specific information will compromise utility competitiveness and that nondisclosure is permitted under the Public Records Act and General Order 66-C.

7. Utilities shall develop and apply for performance based rates in dockets affecting the distribution component of their revenue requirement, and shall be subject to penalty if proposals are not filed for both system-wide reliability and responses to the six most frequent customer service requests by January 1, 1998. Such proposals shall be nondiscriminatory across customer classes.

8. Each respondent electric utility shall have an emergency response plan maintained with designated Commission staff, cooperate with the California Utility Emergency Association, and provide mutual assistance to other respondent electric utilities during emergencies. Emergency operations for purposes of compliance with this ordering paragraph are those circumstances defined as excludable major events. Each respondent utility shall use local media to inform the public in the event of outages giving rise to an emergency of the breadth of the outages and the likely duration of the outage in geographical portions of the system. This paragraph in no way limits respondent electric utilities' obligations to respond to the Office of Emergency Services or any other entity with authority to direct respondents' resources or operations under conditions of emergency, whether defined as in this paragraph or not.

9. The investigation shall be separated from Application 94-12-005 and combined with a rulemaking. We institute a rulemaking for the purpose of proposing and receiving comment on rules for the appropriate inspection, maintenance, and replacement cycles for major distribution facilities.

This order is effective today.

Dated September 4, 1996, at San Francisco, California.

DANIEL Wm. FESSLER
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

President P. Gregory Conlon, being necessarily absent, did not participcate.

APPENDIX A
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I. System-wide Reliability Indices

1. System Average Interruption Duration Index ("SAIDI")

SAIDI is defined as the total minutes of sustained customer interruption divided by the total number of customers, expressed in minutes per year. It may be expressed in smaller time periods (month or quarter) or smaller portions of the system (region or circuit) upon request. It characterizes the average length of time customers were without power during the time period.

2. System Average Interruption Frequency Index ("SAIFI")

SAIFI is defined as the total number of sustained customer interruptions divided by the total number of customers, expressed in interruptions per customer per year. It may be expressed in smaller time periods (month or quarter) or smaller portions of the system (region or circuit) upon request. It characterizes the average number of sustained power interruptions for each customer during the time period.

3. Momentary Average Interruption Frequency Index ("MAIFI")

MAIFI is defined as the total number of momentary customer interruptions divided by the total number of customers, expressed as momentary interruptions per customer per year. It may be expressed in smaller time periods (month or quarter) or smaller portions of the system (region or circuit) upon request. It characterizes the average number of momentary power interruptions for each customer during the time period.

4. Standards for Calculating Reliability Indices

The following common assumptions are to be used in accummulating outage data for standardized reliability indices.

a. Definition of sustained and momentary outages:

A sustained outage is an outage that lasts at least 5 minutes; a momentary outage is an outage which is less than 5 minutes.

b. Planned outages:

Planned outages are those outages which the utility schedules and customers are notified in advance. These outages are sometimes necessary to connect new customers or perform maintenance activities safely. They are excluded in outages used to calculate reliability indices.

c. Excludable major events:

Each utility will exclude from calculation of its reliability indices major events that meet either of the two following criteria: (a) the event is caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government, or (b) any other disaster not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

d. Outage recording start and stop times:

The beginning of an outage is recorded at the earlier of an automatic alarm or the first report of no power. The end of an outage is when all customers have power restored.

e. Tracking level:

Outages involving a primary distribution circuit are tracked by all utilities. These outages will be included in reliability indices. Outages which do not involve a primary distribution circuit (i.e., secondary, line transformer only or service only) will not be included in the standardized indices.

f. Partial circuit outage customer count:

Where only part of a circuit experiences an outage, the number of customers affected is estimated, unless an actual count is available. When power is partially restored, the number of customers restored is also estimated.

g. Outages caused by power restoration process:

When customers lose power as a result of the process of restoring power (such as from switching operations and fault isolation), the duration of these additional outages is included, but the additional number of interruptions is not.

h. Customer geographic segmentation:

Outages can be segmented by circuit and by district or division. Utilities should maintain information adequate to calculate reliability indices on these bases upon request.

5. Reporting Standards

Each utility will report SAIDI, SAIFI, and system MAIFI in an annual report by March 1 of the year following the calendar year reflected by the data used to calculate the indices. The report shall also include information about any group of customers commonly served by a circuit (no smaller than the facilities below the level of the last step-down transformer in the area) that experience more than one 5 (or more) minute outage per month on a rolling annual average basis, after exclusion of major events as defined above. The report will be filed with the Commission's Executive Director, and copies will be made available to interested persons upon request.

Each utility will also report and identify the 10 largest outage events, and indicate whether any of them were excluded from the reported indices. For each major event excludable under the standard above, the utility will report the total number of customers affected, the number of customers without service at periodic intervals, the longest customer interruption, and the number of people used to restore service.

Information about SAIDI, SAIFI, and system MAIFI on a circuit level shall be recorded by utilities. Utilities must provide this information upon request to any interested person over time periods no smaller than one month.

Utilities will use their best efforts to normalize historical data over the last 10 years to the reliability measures in this Appendix, and provide that information with each annual report. Utilities first annual report should describe limitations in data that affect normalization, and provide their best estimate of the statistical error inherent in the normalized indices.

APPENDIX A
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II. Accident Reporting

1. Each utility shall provide both notice and a written report to designated staff of the CPUC within thirty days from the date of reportable incidents, giving a detailed and thorough account of the incident. Supplements to such reports are permitted but not required.

2. Reportable incidents are those: (a) resulting in fatality or personal injury rising to the level of in-patient hospitalization and involving utility owned facilities, or (b) are of significant public attention or media coverage and involve utility owned facilities.

3. Notice of an incident shall be within two hours of the utility's determination that the incident is reportable and include the time and date of the incident, the time and date of the notice to the Commission, location of the incident, a detailed description of the incident, fatalities involved, identification of facilities and injured persons, any third party property damage, the name and phone number of a utility contract person. Notice shall be effectuated by one of the following means: (a) an established CPUC Incident Reporting Telephone Number designated by the Commission's Utility Safety Branch, (b) an e-mail address designated by the Commission's Utility Safety Branch, or (c) facsimile using a form agreed upon with the Commission's Utility Safety Branch at numbers the Branch may designate during normal working hours. Telephone notices outside normal working hours shall be followed by a facsimile report by the end of the next working day.

4. Incidents involving estimated property damage of the utility or others estimated in excess of $20,000 that are allegedly attributed to utility owned facilities shall be reported within 60 days in a form acceptable to the Commission's Utility Safety Branch.

(END OF APPENDIX A)