Decision 01-07-027 July 12, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into Distributed Generation.	Rulemaking 99-10-025 (Filed October 21, 1999)

(See Appendix A for List of Appearances)

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INTERIM DECISION ADOPTING STANDBY RATE DESIGN POLICIES

1. Summary

This decision is part of a broader consideration of rules and policies affecting the deployment of onsite generation facilities. Such facilities are "onsite" in the sense that they are located on or in close proximity to the property of the customer or customers whose load the facilities are designed to serve. Here, we adopt interim standby rate design policies for onsite generation facilities that are interconnected to and operate in parallel with the distribution system in accordance with Rule 21.

During the pendency of this proceeding, the context for setting standby rates has changed in several fundamental ways. Most basic has been the continually-expanding disaster in wholesale electric markets, permanently altering our expectations for the functioning of electric markets, and shaking many of the assumptions underlying the record in this proceeding.

In addition, the Legislature has spoken decisively by establishing short term policy for the application of standby charges to onsite generation. Most onsite generators going into operation in the next two years are exempt from standby charges for at least the next ten years.[1] The exceptions are diesel-fired generators and facilities with capacity in excess of five megawatts (MWs).

Further, the Legislature has expanded the previously more-limited net metering program to apply to renewable onsite generators of one MW or less, in

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[1] Pursuant to Section 353.1(a) of the Public Utilities Code, this exemption applies to onsite generators meeting other criteria that comment initial operation between May 1, 2001 and June 1, 2003, except that gas-fired generators that are not operated in a combined heat and power application must commence commercial operation no later than September 1, 2002.

all customer classes. This not only allows such customers to net unneeded power against power supplied by the utility at retail prices, but also shields those customers from the imposition of any additional charges, including standby fees.

We are left with the need to implement these legislative directives and to define a broader policy to apply to those facilities not included within the statutory exemption due to size, fuel choice, or date of initial operation.

We direct the utilities to file standby rate design applications consistent with the interim policy guidelines within 60 days; we will adopt permanent rates within utility-specific proceedings. The rate design policy we approve today provides guidelines for rate design of the standby rates charged to non-exempt customers employing onsite generation to cover all or some portion of their load. These policies will apply to any non-exempt onsite generation facility requiring some level of standby service, whether for supplemental, backup, or maintenance purposes. Such facilities include self-generation, cogeneration, microcogeneration, and qualifying facilities (QFs). We also adopt the Independent Clean Energy Tariff (ICE-T) proposal recommended by the California Solar Energy Industry Association (CalSEIA). Respondent utilities are directed to submit advice letters to implement the ICE-T proposal within 15 days of the effective date of this order. While consistent with the Legislature's recent expansion of the net metering program, ICE-T extends the protection from standby charges to solar generators not taking advantage of net metering.

2. Background

This rulemaking was opened to develop specific policies and rules to facilitate the deployment of distributed generation in California. The Commission recognized that distributed generation will provide end-users with additional choices to supply their electricity needs. We recognized that distributed generation is likely to increase competition in the electric generation market, and may assist in improving and maintaining distribution system reliability.

The Commission identified several issues to be covered in two phases. The first phase addressed interconnection standards, the ownership and control of distributed generation, distribution wheeling, distribution system planning, valuation and net metering, educational efforts and outreach to governmental agencies. The second phase addressed rate design, stranded costs, and streamlining of the California Environmental Quality Act.

The objective of Phase 2 of the rulemaking is to determine general policy guidelines for rate design associated with distributed generation. Specific rate design proposals for each of the utility distribution companies were not presented but are to be the subject of future utility-specific rate design applications, such as each utility's General Rate Case or Performance Based Ratemaking proceeding. This decision provides general policy guidelines and guidance associated with standby rate design only. While we initially intended to deal with all rate design issues simultaneously in the final Phase 2 decision, recent events have led us to reevaluate that approach.

Dramatic developments in California's generation market have occurred since this rulemaking was initiated. The state is in the midst of a generation shortage, and new generation, large and small, provides substantial value in addressing that shortage. Because the scope of this proceeding was determined before the electricity crisis began, this case has not focused on the role distributed generation may have in mitigating the state's electricity crisis, or on how new distributed generation units might impact the generation marketplace.

Indeed, in other dockets, the Commission is looking at the appropriate level of incentives for renewable or super clean distributed resources. On September 30, 2000, Governor Davis approved Assembly Bill (AB) 970 (Chapter

329, Statutes of 2000) to amend Section 399.15 of the Public Utilities Code. Section 399.15 directs the Commission to adopt "differential incentives for renewable or super clean distributed generation resources." On October 17, 2000, Commissioners Lynch and Neeper issued an Assigned Commissioners' Ruling on Implementation of Public Utilities Code Section 399.15(b) in R.98-07-037. A draft decision in that proceeding was issued on March 2, 2001.

In recognition of the current electricity crisis, and the potential for distributed generation to assist in mitigating the price and reliability problems associated with that crisis, we today adopt an interim decision addressing one of the issues that promises to provide immediate benefit to California customers. The significant potential for outages has raised to the forefront the need to review and revise the policies and standby rate design associated with distributed generation to provide additional options for consumers. At the same time, we recognize the need to revisit these issues at some future time when the electric generation markets have stabilized.

As we continue to consider issues separately, we need to remain cognizant of the cumulative nature of our decisions. We recognize that, in some cases, the Commission's ultimate decision on some of the general policy issues in Phase 1 or 2 may necessitate adjustment(s) to the rate design policies we adopt in this decision, therefore, we are adopting this decision on an interim basis.

3. Procedural History

A prehearing conference was held on December 1, 1999. The Assigned Commissioner issued a Scoping Memo and Ruling on January 19, 2000, which clarified the scope of the proceeding and established the procedural schedule. As directed by D.99-10-065, the Commission's Energy Division conducted a workshop on March 29, 2000 to discuss the scope of Phase 2 rate design testimony. The Assigned ALJ issued scoping rulings on April 14, 2000 and June 9, 2000 which further clarified the scope of Phase 2.

Phase 2 testimony was served by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), Sierra Pacific Power Company (Sierra), the Office of Ratepayer Advocates (ORA), the Natural Resources Defense Council (NRDC), jointly by The Utility Reform Network (TURN), Utility Consumer Action Network (UCAN), and NRDC (together TURN), CalSEIA, jointly by the Cogeneration Association of California and the Energy Producers and Users Council (CAC/EPUC), jointly by Capstone Turbine Corp., Inc. (Capstone), Caterpillar, Inc. (Caterpillar), Distributed Power Coalition of America, Elektryon, Honeywell Power Systems, Inc., and New Energy, Inc. (together Capstone, et al.), the United States Department of the Navy and All Other Federal Executive Agencies (FEA), Duke Energy North America (Duke), Enron Energy Services Inc. and Enron North America Corp. (Enron), Aglet Consumer Alliance (Aglet), jointly by Greenlining Institute and the Latino Issues Forum (GI/LIF), jointly by University of California, California State University System, and California Department of General Services (together State Consumers), and Solar Development Cooperative (SDC).

Rebuttal testimony was served by PG&E, SCE, SDG&E, Edison Electric Institute (EEI), FEA, CAC/EPUC, GI/LIF, Capstone, ORA, California Independent System Operator (CA ISO), TURN, and EEI. The Commission held seven days of evidentiary hearing in September 2000. The parties that served testimony, as well as the City and County of San Francisco (CCSF), filed opening briefs on November 13, 2000. Reply briefs were filed on December 13, 2000. A comparison exhibit was submitted on January 3, 2001.

4. Standby Rates Today

In order to determine whether the existing standby rate design policies fit current market conditions, it is appropriate to review the current standby rate design. Current standby rate design differs significantly among utilities and is quite complex. The timing of the Commission's review of rate design and cost allocation for each utility also differs. In this decision we limit our discussion here to the existing standby rate design previously approved by this Commission.[2]

Generally, a customer who has installed generation (either a QF or a distributed generation customer) is required to take service on one of the utility's standby tariffs, in combination with their otherwise applicable tariff. The only exceptions to this requirement exist in the residential and small commercial sectors, where net energy metering allows certain wind and solar facilities to avoid standby rates.

SDG&E's current standby service is provided on Schedule AV-1 for customers with distributed generation facilities, and Schedules S and S-I in combination with AL-TOU or other tariffs for QFs. SDG&E has historically had several tariff options that are designed to provide service to customers with non-QF installed generation sources. These include Schedules AV-1, AV-2, AV-3, and RTP-2. Schedule AV-1 is the most commonly utilized of these options. As of January 31, 2000, SDG&E had 41 customers taking service on AV-1, and this represented approximately 80% of all customers using these types of rate

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[2] PG&E, SDG&E, and SCE all have pending rate design applications before the Commission. We describe some of the utility proposals in those applications in the Positions of Parties Section as they relate to standby rates.

options. AV-1 remains open, all others were closed in the rate design window proceeding.

Schedule A-V1 contains a Signaling Equipment Charge, Basic Service Fee, Non-Coincident Demand Charge, Contract Minimum Demand Charge, Signaled Period 1G Energy Charge, Semi-Peak Energy Charge, and Off-Peak Energy Charge. All of these charges vary based on the customer's service level and defined season of the year. The Signaling Equipment Charge is a one-time charge for new customers of $4,580, and covers SDG&E's costs of installing necessary signaling equipment at the customer's site. Under the terms of AV-1, a signaled period, termed 1G, is called when SDG&E's system load approaches peak levels or when either the utility or the ISO called a stage 2 or stage 3 emergency. Customers are notified via electronic signal when a signaled period 1G will commence, and energy prices during this period are much higher than during other periods. Customers with generation facilities usually will operate these facilities during the high-priced signaled period 1G. AV-1 customers pay lower prices to the utility in all periods other than the signaled period, and there is no on-peak demand charge on AV-1. Customers on AV-1 also have the option of signing up for a specified Contract Minimum Demand level, if they are not able to shed their entire load during the signaled periods.

A customer taking service under Schedules S or S-I pays a $/kW standby demand charge based on its contract demand, and receives a waiver of the non-coincident demand charges normally paid on the otherwise applicable tariff through a credit to its bill when its distributed generation unit operates. This credit is not restricted to distributed generation with physical assurance[3] or distributed generation operating under a Form Contract.[4] If an SDG&E customer's generating facility does not operate, due to a forced or scheduled outage, the customer continues to pay the Schedule S standby demand charge, but the level of the outage, on a $/kW basis, is subtracted from its recorded maximum demand to reduce the non-coincident demand charge on the otherwise applicable tariff. If the outage has been scheduled with SDG&E's concurrence, the on-peak demand charges on the otherwise applicable tariff are waived up to the contract standby level. SDG&E's standby rate design is structured such that Schedule S and S-1 are used to bill standby accounts only for their contracted standby load, but not for actual usage. All energy usage is billed under the otherwise applicable tariff.

SCE's tariffs function in a similar manner. SCE's schedule S is applicable to customers taking service under a regular SCE rate schedule who have an alternate power source. Schedule S operates as a rider to the customer's otherwise applicable tariff. Under these schedules, the customer's contracted standby demand, also referred to as standby reservation capacity, is established at the lower of the nameplate capacity of the generator and the customer's

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[3] For purposes of this decision, physical assurance is defined as the application of devices and equipment that interrupt a DG customer's normal load when DG does not operate. (Derived from SDG&E Opening Brief-Phase 1, p. 31.)

[4] SDG&E proposes to enter into Form Contracts of one-year duration with DG customers for the provision of electric distribution service. DG customers will provide physically assured load reduction based on either the availability of installed DG capacity, or by load reduction if the full capacity is unavailable. The Form Contract specifies the amount of available DG capacity, and provides for either a bill credit or monthly payment based on reduced on-peak demand charges.

maximum expected demand. The standby demand charge on SCE's current Schedule S is the same as the facilities-related demand charge on the customer's otherwise applicable tariff and is calculated on a $/kW basis. These charges are designed to recover the costs of transmission and distribution facilities dedicated to the customer's use that do not vary with usage and exclude coincident capacity costs that can be avoided by a standby customer, or group of standby customers, by reducing their demand at system peak. Because standby customers' demand charges reflect facilities-related costs assigned to customer based on their non-coincident maximum demands at their sites, SCE argues that its rates already reflect diversity, but no specific diversity factor is applied to the standby demand charge. A monthly reservation charge ($/kW) also applies to all kW of standby demand.

The distributed generation customer pays all of the applicable charges under the otherwise applicable tariff in addition to the standby and generation reservation charges. However, when the otherwise applicable tariff contains a facilities-related demand charge, prior to applying the facilities-related demand charge, the standby demand is subtracted from the facilities-related billing demand[5] to avoid duplicate demand charges.

None of the other SCE demand charges are reduced for standby demand. The customer's total demand charge is the sum of the adjusted facilities-related demand component and the time-related demand component from the otherwise applicable tariff. Backup charges are based on the otherwise applicable tariff, except that instead of the otherwise applicable tariff's peak demand charge, backup customers under Schedule S will pay the standby demand charge. In

[5] The level of recorded demand in a given month or billing period is the billing demand.

addition to the demand charges, when the customer takes energy from SCE, the customer will be charged based on the energy charges of its otherwise applicable tariff.

PG&E's standby tariff, Schedule S, is structured to function as a stand-alone tariff for customers whose distributed generation unit normally meets their load and who only require backup or maintenance standby service. In this situation, only PG&E's Schedule S would apply. PG&E's Schedule S includes: 1) a monthly reservation charge equal to 85 percent of the customer's contract reservation load[6]; 2) time-differentiated, seasonal energy charges ($/KWh) for distribution based on the actual backup power purchased; 3) customer charges; and 4) reactive demand charges. No charges are applied from other rate schedules.

For PG&E customers whose load normally exceeds their generation capacity, the customer's otherwise applicable tariff is used in combination with Schedule S. The reservation charge from Schedule S is applied based on the contract capacity. The otherwise applicable tariff is used to calculate customer charges and usage charges. Currently, if a supplemental service[7] customer imposes a demand due to an outage of its generator, and the otherwise applicable tariff is the E-19 or E-20 interruptible tariff, the customer's charges on E-19 or E-20 are reduced by the standby reservation charge from Schedule S in order to avoid double payment for reservation charges. For supplemental

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[6] PG&E's contract capacity is subject to a three-year ratchet provision to allow for increases and decreases over time based on DG performance.

[7] PG&E refers to this service as mixed-use. For consistency, we refer to this type of service as supplemental service throughout this decision.

standby customers, the otherwise applicable rate would apply to service beyond the level served by the generator, together with the standby charge.

PG&E's current rates reflect a diversity discount developed based on experience with generators serving onsite load connected at the transmission level. Currently, distribution level distributed generation customers receive the same discount off the actual cost of standby service based on assumed lower costs to the utility resulting from generation diversity.

For all three utilities, the demand and energy charges also vary according to interconnection voltage level (secondary, primary, and transmission).

5. Positions of the Parties

Phase 2 testimony was submitted on July 3, 2000. Circumstances then were quite different from those we face today. Many parties reference the Power Exchange and other entities that may no longer function in the same capacity, or indeed, may no longer exist. We present the positions of parties within the context to which testimony was originally served in order to retain the relevant value of the concepts and proposals, recognizing that certain specific references may no longer apply. Not every party that served testimony addressed standby rate design; we limit our summary of the positions to the standby rate design issue.

5.1 Pacific Gas and Electric Company

PG&E summarizes its position in this proceeding by stating that standby rates for distributed generation customers should reflect the full cost of service, just as charges for all other customers must reflect the full cost of service. PG&E states that standby rates should continue to contain: 1) a contract reservation charge; 2) a kWh based distribution charge for backup service[8]; 3) an energy (i.e. commodity) charge; 4) a customer charge; and 5) a reactive demand charge. PG&E's current Schedule S combines the kWh-based distribution charge, the energy charges, and the nonbypassable customer charges in the "energy charges" portion of its tariff.[9] PG&E's kWh-based distribution charge is intended to ensure that standby charges are based, in part, on frequency of use in order to provide assurance that customers with non-operating generating plants do not sign standby contracts simply to get the lower reservation charges, rather than the full requirements demand charges.

PG&E's customer charge would recover distribution-related costs including metering, service connection, and customer service costs that are not avoided by a customer's election to meet some or its entire load with distributed generation. The customer charges would be the same as those on the otherwise applicable rate schedule, based on the reservation capacity. PG&E would maintain the current standby service reactive demand charge as an incentive for customers to fully provide reactive current requirements associated with the load being served by distributed generation.

PG&E maintains that today's distribution level standby charges are too low for three reasons. First, because there are relatively few distributed generation units connected at distribution voltage, there is virtually no diversity on individual distribution circuits. PG&E states that while such diversity exists at the transmission level, it does not currently exist at the distribution level. PG&E

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[8] Backup service is service supplied by the utility to replace the generation from non-utility facilities during periods of unscheduled outages.

[9] PG&E Opening Brief- Phase 2, p. 13.

argues that while the 38% diversity factor embedded in PG&E's current standby charges accurately reflects the cost to serve standby customers served at transmission voltage, this diversity factor significantly overstates the level of generation diversity for customers connected at distribution voltage. Second, distribution planners cannot presume that a given unit will operate at the times needed for system reliability. Third, because of lack of diversity, PG&E must plan to serve all standby load on a circuit in the event of a circuit outage and therefore it incurs distribution infrastructure costs to serve that load, even if distributed generation is installed.[10]

PG&E does not object to using a distribution level diversity factor to set standby rates, so long as the factor employed matches the extent to which generation diversity actually permits the utility to avoid building distribution upgrades. PG&E recommends that standby rates for distribution level customers be revised to reflect the actual costs caused by such customers.

PG&E also opposes proposals that would offer lower rates for infrequent use associated with more reliable distributed generation units. PG&E believes that the primary problem with these proposals is that they propose to collect less revenue than current rates without reducing the cost of providing the service. If

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[10] When a circuit is de-energized, any DG units must remain separated from the distribution circuit to prevent backfeed into the de-energized line. When the circuit is being re-energized, the DG units are still separated from the system; after the circuit is energized, the DG units can be synchronized with distribution system voltage frequency and phasing. In such events, load must be restored and served by PG&E's distribution system prior to the availability of the DG. In other words, after an outage, all load on a distribution circuit, including the load formerly served by the DG, will come on simultaneously and need to be served by the distribution circuit. Therefore, PG&E must plan and reserve distribution capacity to serve 100 percent of the standby load. This phenomena becomes even more significant when blackouts are more frequent.

the utility is standing by with distribution facilities that must be available to provide service at all times, then the amount of wires reserved for such service is the same whether the customer calls on those lines 10 hours per year or 1000 hours per year. PG&E currently offers separate, lower-cost options for maintenance power since maintenance power can be scheduled over weekends and during the winter season when the volumetric components of the rate are significantly lower. PG&E does not believe any further incentive for scheduled maintenance is necessary or required.

Finally, PG&E believes that standby customers should also continue to pay nonbypassable charges for public purpose programs, nuclear decommissioning, and transition costs, unless an exception applies.

5.2 Southern California Edison Company

SCE opposes any efforts to depart from efficient, cost-based rates to “facilitate” distributed generation deployment. Reflection of truly fixed costs to serve standby customers in variable energy charges is inefficient because it allows these customers to avoid paying their fair share of fixed costs. The Commission’s rate design policies should follow sound economic principles rather than be predicated on providing subsidies to customers to promote the installation of distributed generation. SCE argues that there is no cost-based justification for reducing standby distribution rates to reflect alleged system-wide capacity benefits. SCE asserts that standby rates do not, and should not, relate to commodity energy. Furthermore, SCE argues, even if one could establish that generation capacity benefits are derived from distributed generation, there is still no justification for reflecting such benefits in distribution charges.

SCE recommends that the goal when designing standby charges should be “to achieve rates which reflect the costs the customer imposes on the system.”

(SCE Opening Brief-Phase 2, p. 11, citing D.96-04-050.) SCE asserts that both its current standby rate structure, and its proposals in its Post Transition Rate Design (PTRD) Application (A.00-01-009), are based on an analysis of the long-run marginal costs to serve SCE's various customer groups. SCE's proposal in this proceeding is designed to be consistent with its PTRD proposal.

SCE's proposed post-transition rate design standby rates include: 1) a "grid" charge; 2) a standby demand charge; 3) a customer charge; 4) any applicable non-bypassable charges such as recovery of nuclear decommissioning, public purpose, and transition costs; and 5) any ISO-related charges that must be passed through to retail customers. In addition, when a distributed generation customer requires backup service, the distributed generation customers would pay SCE's purchase energy charge. In its PTRD application, SCE proposes to include all fixed distribution costs in a "grid" charge to be paid by all full service and standby customers based on their size, reflecting the expected maximum demand they can place on the distribution system. The grid charge would pay for the costs of distribution facilities dedicated to the distributed generation customer's use, irrespective of when or if backup load is placed on the system. This charge would include the cost of that portion of the distribution and transmission system that connects the distributed generation customer to the alternate sources of power but does not vary with the level of demand on the system.

In addition to the grid charge, SCE recommends that all standby customers pay a standby demand charge calculated by multiplying the peak demand charge on the otherwise applicable tariff by an Effective Demand Factor. The Effective Demand Factor reflects the diversity of standby customer's demands at the time of distribution circuit peak and is calculated on the backup demand of existing customers. Under SCE's post-transition proposal, the lower standby demand charge would apply during months when the onsite generator operates at a capacity factor above 20%. SCE would apply the peak demand charge of the otherwise applicable tariff to the customer's contracted standby demand in the months when the generator capacity factor drops below 20% or if the customer does not install generation metering. SCE plans to update the diversity factors reflected in current rates in future ratemaking proceedings as more generation metering becomes available and as more small generators are employed in the future.

If a customer has supplemental load, which is the portion of the customer's total load that is regularly delivered by SCE, that load would be billed at the customer's otherwise applicable tariff. All other usage-based charges, except the peak demand charge, for the backup load will be billed based on the customer's otherwise applicable tariff. The standby demand charge will apply to the customer's contracted standby demand only. SCE proposes to require that standby customers have the appropriate generation and load metering needed to separately identify their back-up and supplemental loads.

SCE recommends that standby customers continue to pay non-bypassable charges. Standby customers, except those who use cogeneration, must continue to pay the Competition Transition Charge (CTC) based on their total consumption regardless of whether it is supplied by their self-generation system or through SCE's T&D system.[11]

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[11] This exemption from CTC for cogeneration customers derives from Pub. Util. Code § 372(a)(1) which exempts customer who install cogeneration systems from payment of CTC after June 30, 2000.

SCE believes that there should be consistency among utilities in standby rate design with respect to principles such as cost components, data and probability of distributed generation failure used in determining the rate levels. However, due to the differences in the methodologies for calculating their marginal T&D costs, some differences in the utilities' standby rate structures and levels should be expected, just as there are approved differences with regard to rate structures for other customers.

If distributed generation customers use the T&D system at a lower frequency because their distributed generation units fail infrequently, SCE argues this will be reflected in the design of future standby rates because standby customers' load will demonstrate a lower coincidence with distribution circuits' peaks. Customers requiring a lower level of reliability can take service on interruptible rates that allow the utility to avoid certain capacity costs. SCE's current interruptible rate schedules were closed by the Commission to new customers. Standby customers, like all other customers, can participate in market-driven curtailment programs sponsored by the ISO. SCE also states that there is no justification for a TOU standby schedule, as there are a number of distribution circuits that peak in traditional off-peak hours and some that peak in the winter season.

5.3 San Diego Gas & Electric Company

SDG&E recommends that the Commission: 1) adopt policies that are cost-based and that provide for no artificial barriers to or supports for distributed generation; and 2) authorize SDG&E to provide credits to customers when distributed generation is installed at the right time, in the right location, of the right size and with physical assurance, such that SDG&E is able to defer a distribution capacity addition.

SDG&E's current standby rates provide a credit to distributed generation customers when the distributed generation unit operates. This service is provided on Schedule AV-1 and related tariffs. This credit is not restricted to distributed generation with physical assurance or distributed generation operating under a Form Contract. As a result, SDG&E states that its current rules provide for a credit to distributed generation without a reduction in cost to SDG&E. SDG&E states that, unless distributed generation is installed under one of its two proposed Form Contracts, or is installed with physical assurance, standby rates for distributed generation should recover the same amount of revenues for distribution from the customer with or without the operation of the distributed generation unit.

In its Form Contract 1, SDG&E proposes to provide credits to customers that install distributed generation at the right time, in the right location, of the right size and with physical assurance such that SDG&E is able to defer a distribution capacity addition for a period of at least a year. For customers receiving standby service under Form Contract 2 (where the distributed generation is installed with physical assurance anywhere on SDG&E's system), SDG&E has proposed that a customer's on-peak demand will be reduced for billing purposes to the load level that would have existed had SDG&E called for the running of the distributed generator for 100% of the on-peak hours.

SDG&E states that when distributed generation relied on for distribution capacity does not operate, it affects more than the service drop at the customer's premise. For example, on a circuit with one or more distributed generation units, the entire circuit will see an increase in load when a distributed generator is not operating. This will occur unless there is physical assurance that a corresponding amount of load will be dropped when the distributed generator is not operating.

SDG&E concurs with PG&E that, when a circuit breaker is opened to clear a fault and then reclosed, distributed generation units on that circuit will separate from the utility system leaving 100% of the load served by those distributed generation units for SDG&E to serve. SDG&E had almost 700 of these momentary outages in 1999. This separation requirement is part of each utility's Rule 21 interconnection requirements.

SDG&E is not opposed to standby rates that reflect diversity and reliability factors, however, due to the radial design of the distribution system, it believes it is impossible for units on one circuit to provide diversity benefits to a different circuit. SDG&E states that diversity exists on a networked system, such as the transmission system, because power can flow in multiple directions, but that is not the case for radial distribution systems. SDG&E contends that until there are multiple distributed generation units on any given distribution circuit, it is inappropriate to assume any diversity value from distributed generation for that distribution circuit. SDG&E recommends that the Commission reject the proposition that distributed generation provides systemwide benefits to all ratepayers.

SDG&E currently offers firm and nonfirm standby service under Schedules S and S-1 (applicable to customers with QFs). SDG&E states that it would be willing to offer other types of standby services if there was a reasonable demand for such services, however, such services should reflect rates and conditions that are cost-based.

5.4 Sierra Pacific Power Company

Sierra argues the standby charge should include all fixed costs associated with the system capacity needed to replace a distributed generation unit's output in the event of a failure or scheduled maintenance. The standby charges should reflect the fact that a portion of the system is being held available to provide this service. Since the purpose of the standby charge is to collect embedded costs from customers, Sierra recommends standby rates reflect embedded, not incremental costs.

Sierra believes the costs for a standby customer should be the same as for any other customer of similar size and with similar load characteristics. However, Sierra states there are system components that can be shared among standby customers. Furthermore, as not all standby customers require backup at the same time, it may be appropriate to apply a diversity factor to lower the costs associated with serving standby customers. However, Sierra recommends that diversity factors should only be applied where there would be cost savings for the utility, such as a reduction in the amount of capacity need to provide backup service.

5.5 Federal Executive Agencies

FEA recommends three principles to guide the Commission in setting both general and specific rate design policies for distributed generation. First, rates should appropriately reflect costs imposed on the utility system by all customers. Second, the Commission should not encourage or discourage installation of distributed generation, and should not provide incentives to the utilities, nor subsidies to distributed generation customers. Third, existing standby rates are not appropriately designed and do not reflect the outage characteristics and range of reliability of generation facilities. FEA believes the Commission should institute a separate proceeding to consider the design of standby rates.

These principles encourage the Commission to design standby rates on a non-discriminatory, cost-causation basis to ensure policies that facilitate, but do not subsidize, the development and installation of distributed generation. FEA contends that subsidization sends the wrong price signals, and could result in deployment of uneconomic resources. Likewise, distributed generation customers should not pay standby rates designed to recover full costs if those costs are equivalent to what a full requirements customer would pay, unless the standby customer has load characteristics the same or similar to a full requirements customer. FEA disagrees with State Consumers that because most distributed generation customer loads are small, they impose no costs on the distribution system.

With respect to distributed generation, FEA believes standby charges fall into two categories: 1) standby rates applicable to the generation resource itself, and 2) standby rates applicable to the T&D systems. Generation standby costs should reflect the probability that the distributed generation facility will cause costs to be incurred by the backup generation resource provider. Similarly, with respect to T&D facilities, the standby charge should consider the probability that an outage of the distributed generation facility would impose costs on the T&D systems.

FEA believes transmission and distribution costs are attributable to two key factors: the overall level of diversity among individual customer loads on the system, and the reliability of the customer's generating facility. The level of diversity among individual loads defines the total amount of load placed on the system by a combination of resources. The utility must serve the diversified load at any given point on the system. The reliability of the distributed generation unit also dictates the frequency and duration of use of the network facilities by that distributed generation customer.

FEA argues that current standby rates do not adequately reflect the reliability of the distributed generation units being backed up. This hinders distributed generation deployment because of the inherent overcharges to distributed generation customers when these inappropriate rates are applied. FEA asserts that usage-sensitive standby charges would facilitate the development of distributed generation by charging rates more consistent with the cost of providing service. The higher the reliability of the distributed generation, the less likely the need for backup, and thus the lower the standby charge.

As in other tariffs, the standby rate should include appropriate service voltage level distinctions: secondary, primary, subtransmission, or transmission. The higher the voltage level of the system where service is taken, the lower the probability that an outage will occur at coincident peak. At lower voltage levels closer to the customer's meter, there is less diversity. A distributed generation facility on a radial feeder line with only a few customers increases the probability that an outage at the distributed generation facility would coincide with peak system demand.

FEA believes that standby rates should be designed consistent with full requirements service charges. If embedded costs are used to develop full requirements rates, embedded costs should be used to develop standby rates. Similarly, if marginal costs are used for the full requirements rates, marginal costs should be used to develop standby rates.

5.6 Office of Ratepayer Advocates

ORA believes that standby charges, especially reservation charges, can be a barrier to an economically viable distributed generation market if those charges are unreasonable. ORA believes that distribution standby rates should reflect the costs actually imposed on the distribution system by customers who normally utilize distributed generation for their energy needs but rely on the utility for backup service.

ORA contends that, in calculating the marginal costs of distribution service, utilities should not assume that all distributed generation units would shut down simultaneously, thus triggering all standby customers to demand service from the utility. According to ORA, the most important aspect of calculating distribution standby rates is designing sufficient distribution capacity to serve the maximum demand expected within a distribution planning area. ORA testified that, "the UDCs' approach to distribution planning may overstate standby capacity requirements and lead to unnecessary investments in distribution facilities in certain instances because it ignores the low probability of multiple outages of self-generation units." (ORA Ex. 22, Gibson, p. 2-5.)

ORA believes that distributed generation customers must pay some reservation capacity charges at peak times to reflect as accurately as possible the probability they would need standby service during such a period. ORA admits that distribution planning requires the utility to design sufficient capacity to serve the maximum demand expected within a Distribution Planning Area (DPA). But there are differences in diversity between distribution, generation and transmission loads and peaks. A customer's maximum demand is usually less than connected load because a customer does not utilize all its potential electrical equipment at any one time. Thus, utilities do not design distribution circuits to handle the total connected load. ORA recommends that installing standby capacity for each DPA at the size of the largest distributed generation unit in the DPA should be sufficient.

ORA believes distribution standby rates should not be used to reflect any generation-related or system benefits provided by distributed generation. Demand reduction benefits are probably already accounted for in lower rates and lower investment in T&D facilities. Therefore, ORA does not recommend attempting to develop focused incentives to reward distributed generation for system benefits in this proceeding.

ORA suggests that standby rate design ought to be as consistent as possible among the utilities. Since general rate design can legitimately differ among utilities though, ORA recommends this proceeding not mandate that utility standby rates utilize the exact same methodologies. ORA does recommend that certain precepts be applied to all utilities, such as ordering all utilities to consider diversity values in calculating load requirements, but that the Commission should not require utilities to utilize the exact same methodologies.

ORA's proposed guidelines for standby charges are conceptually similar to how standby charges are currently structured, except that current utility presumptions that distributed generation will not operate when needed are too extreme, therefore ORA is not requesting a full-scale revamping of how standby rates are calculated. ORA also supports time-of-use demand charges that reflect the cost of providing service during various times of day or seasons.

5.7 The Utility Reform Network et al.

In their joint testimony, TURN, NRDC, and UCAN (together TURN) state that equity among customers must be considered when establishing standby charges. Ratemaking and rate design should not result in cost shifting between customers who install distributed generation and those who do not. Although the benefits of distributed generation need not be allocated equally across ratepayers, all customers should ultimately realize some benefits. Customers relying on distribution service should pay costs consistent with their reliance on the distribution system. Customers should be allowed flexibility to choose differing amounts of standby services, including variations on timing with appropriate provisions for physical assurance. TURN recommends usage-based, volumetric average distribution rates, and opposes the fixed customer charge proposed by SCE. TURN believes fixed charges are not likely to be consistent with cost causation on the distribution system over the long term.

TURN believes that standby rates should reflect actual costs and benefits to the distribution system. Standby rate design should reflect diversity factors, the availability of differentiated service levels, unit reliability and use of various forms of physical assurance. Standby rate design should also reflect system benefits provided by distributed generation units such as deferral of distribution upgrades, extension of equipment life, and energy supply costs reductions that benefit all ratepayers. TURN believes that these system benefits should be incorporated into the distributed generation rate structure in order to send proper price signals to potential customers.

Like ORA and FEA, TURN disagrees with the claim that utilities must plan and reserve capacity to serve 100 percent of the standby load. TURN believes that the diversity of standby load must be incorporated into the design of standby rates. TURN contends that utility concerns regarding the inability to know with certainty that a distributed generation unit will be operating at times of peak demand can be remedied if customers provide physical assurance.

TURN asserts that the energy and supply benefits of distributed generation may be significant. TURN maintains that it is undisputed that wholesale energy prices in California will be influenced by the addition of new generation capacity and by efforts to achieve peak demand reductions. Therefore TURN suggests deployment of customer-side distributed generation, which performs both supply and demand-reduction functions, can contribute to lowering overall market prices for electricity. Non-participants can benefit from the deployment of distributed generation units only if there are opportunities for all classes to share the cost savings and improved reliability associated with its use. These benefits can be shared if rates are structured to promote the deployment of distributed generation in areas of the distribution system that may otherwise require utility investment to meet existing or projected future load.

Given the clear benefits to non-participants, TURN believes that standby rates should be designed to recognize the value of distributed generation in reducing wholesale energy prices. TURN recommends that the Commission adopt standby rates that reflect, to some extent, the fact that operation of the units during peak periods will provide defined economic savings for all consumers. TURN does not propose the exact quantification of the benefits it identifies, but suggests that it is difficult to conceive that a quantification of these benefits equals zero. TURN contends that failing to consider these benefits will result in excessive standby charges that fail to properly value the costs and benefits of customer-owned distributed generation to the utility. TURN recommends that the Commission direct the utilities to design standby rates for distributed generation that recognize the benefits in order to encourage deployment of distributed generation that will produce cost savings for the utility and its customers.

TURN also suggests that customers taking standby service have their distribution tariffs adjusted based on the reliability of the distributed generation unit. Such reliability adjustments could be done on a technology-specific or project specific basis. TURN argues that even SCE agrees, stating that this approach is warranted because "if a customer generation unit fails more often, it is more likely that the peak demand of that customer would be more coincident with distribution circuit peak than a customer whose generation fails less often." (TURN Opening Brief-Phase 2, p. 21, citing SCE Witness Jazayeri, RT 1292.) TURN believes that this type of rate structure would properly identify and reward the ability of distributed generation units to provide consistent system support during periods of peak distribution usage.

Finally, TURN supports the concept of time of use standby rates that provide incentives for distributed generation customers to operate their generation in a manner consistent with demand peaks in the local distribution system.

5.8 State Consumers

State Consumers encourage the Commission to adopt "forward looking" rate design policies, particularly with respect to standby charges. Such policies should recognize that customers integrate energy procurement, conservation, energy efficiency and other strategies to manage their energy needs. State Consumers testify that the components of standby rates should be unbundled, usage-based, and priced individually to reflect actual cost-causation. State Consumers did not present a definitive evaluation of current standby rate structures, but rather present recommendations on standby rate policies to reflect a competitive market structure for energy procurement. This approach could also consider location-specific standby rates. In no case do State Consumers recommend increasing standby rates beyond existing levels.

State Consumers recommend the Commission adopt incremental marginal cost pricing and cost causation allocation methods for each component of standby charges. State Consumers support market-based pricing for the energy component of standby rates, whether that energy is obtained from the Power Exchange, through bilateral contracts, or demand bidding systems. State Consumers assert that there is no reason why the utilities must be the sole providers of the generation portion of standby service. State Consumers believe standby customers should have the ability to purchase power when they need it at a competitive price. There should be no special standby rate for energy, as there is no generation capacity dedicated solely to provide standby energy. Customers should be able to access other entities for the energy portion of standby service.

State Consumers take the position that standby customers are significantly over-allocated responsibility for distribution revenue recovery, while imposing essentially no incremental distribution costs. State Consumers state that standby customers cause minimal distribution resource additions, citing the relatively small number of standby customers currently taking standby service. According to State Consumers, PG&E serves approximately 300 customers on its standby tariff. State Consumers further state that PG&E's 1999 coincident system demand served under its standby tariff accounts for approximately 0.25 percent of total system energy volumes. As a rate class, PG&E's standby customers pay 38 percent of total costs. (State Consumers Opening Brief-Phase 2, p. 10. See also Exhibit 34.)

State Consumers recommend that the Commission require the utilities to submit calculations of distributed generation impacts on system planning forecasts to support any future standby rate applications.

5.9 California Independent System Operator

According to CA ISO, standby charges should take into account the methodology for setting charges and allocating costs at the wholesale level and the impact of different approaches at the retail level. CA ISO indicates that FERC has jurisdiction over the methodology for the allocation of wholesale and transmission costs, but this Commission has jurisdiction over the design of distribution and retail rates, except for the unbundled transmission component of retail rates. Entities providing transmission and other wholesale services subject to the jurisdiction of FERC should be allowed to collect the costs of providing those services but should not over-collect those costs from customers.

The CA ISO transmission access charge is assessed to and collected from customers by the utilities for all end use customers within their service territories. The grid management and ancillary service charges are assessed to scheduling coordinators. In individual proceedings at Federal Energy Regulatory Commission (FERC)[12], the CA ISO proposes to assess different types of CA ISO-administered charges based on gross load[13] within the ISO control area, including load served by self-generation. These charges include the transmission access charge, the control area services component of the grid management charge, and charges for (or responsibility to self-provide) ancillary services. CA ISO claims that this Commission must consider the structure and allocation of CA ISO administered charges in determining retail standby rates.

The CA ISO does not claim that this allocation must predetermine the allocation of charges at the retail level. Moreover, the ISO recommends that CPUC and FERC jurisdictional components of rates be harmonized so that wholesale costs are collected accurately. Thus costs collected in FERC jurisdictional components should not be included in CPUC jurisdictional components and vice versa, and all legitimate costs should be accounted for in either FERC or CPUC jurisdictional components.

The CA ISO does not take a position on the appropriate billing determinant(s) for purely CPUC jurisdictional components of retail standby rates. Thus, for example, if some portion of the cost recovery component of standby rates is currently determined based on usage volume for net load[14], the

[12] Related FERC proceedings include Docket Nos. ER00-2019-000, ER01-313-000, and ER98-997-000.

[13] Gross load is the customer’s total onsite load, whether served by self-generation or the utility.

[14] Net load is the customer’s remaining load not served by self-generation. Net load is measured at the point of common coupling.

CA ISO is not proposing that billing determinant for this component should now be based on gross load.

The CA ISO's comments as to the appropriate billing determinants apply to the allocation of CA ISO-administered charges, and to consideration of this allocation, for purposes of designing the components of retail standby rates that correlate to CA ISO services. The CA ISO urges this Commission to be clear as to the billing determinant to be used for each standby rate component so that CPUC and FERC jurisdictional requirements can be implemented without anomalous or unintended results.

5.10 Enron Energy Service Inc. and Enron North America Corp.

Enron states that it is widely recognized that standby rates will continue to represent a decisive factor for consumers who are considering distributed generation installations. Enron maintains that standby rates should fairly compensate utilities for the costs associated with facilities needed to provide standby service to distributed generation customers, and at the same time, utilities should not be overcompensated for these services by requiring customers to pay for services that they do not request or use. The challenge is to set rates that equitably assign cost responsibility to distributed generation customers who need these services without creating incentives for customers to "island" load from the grid.

Enron recommends that the utilities offer at least two basic standby rate options. One option would involve only a capacity reservation fee priced comparably with the standard delivery tariff that applies to all customers. Under this approach, the distributed generation customer would pay only the reservation fee, which would entitle the distributed generation customer to unlimited distribution services up to the amount of reserved capacity.

The second option would allow distributed generation customers to pay for standby service under a volumetric rate based on the concept of "proportionate responsibility." Under this approach, rates would reflect a distributed generation customer's anticipated contribution to the capacity requirements of key components of the distribution system and the frequency with which the customer uses the system. This option would require utilities to unbundle the major components of the distribution system and assign cost responsibility based on realistic probabilities that distributed generation customers will require use of the distribution system and taking into account the diversity of loads served by distributed generation units. In particular, standby rates should not be premised on the assumption that all standby customers will require distribution services to serve their entire load at the time of system peak.

5.11 Capstone Turbine Corp., Inc. et al.

Capstone, et al.'s recommendations regarding standby rate design relate primarily to fixed versus usage-based rates. Capstone, et al. advocates that since distribution costs vary with customer usage, usage-based pricing is the fairest and most efficient way for utilities to recover both fixed and variable costs associated with distributed generation and to reflect the costs of system expansion. Capstone, et al. suggests that shifting from high fixed charges and demand charges that are insensitive to usage, toward usage-based charges that encourage demand-responsive behavior, need not compromise the objective of cost-based charges. Such a shift means only that utility costs are recovered differently.

Capstone, et al. also emphasizes that costs imposed on the system can be collected through usage-based charges differentiated as it proposes, and may include per-kWh demand charges for firm reservation of delivery capacity. Capstone, et al. recommends that standby rates considered should include a capacity reservation fee, differentiated by quantity, firmness, time and location of use. Capstone, et al. states that if standby charges are differentiated along the lines it proposes, customers can decide how much standby they need (perhaps less than their maximum demand); when and how firm they need it (perhaps not at certain times of the day, week, or season); and how much it is worth to them.

At a minimum, Capstone, et al. recommends the utilities should offer two levels of service: firm and nonfirm. Standby charges should not be used to recover stranded costs, exit fees, bypass charges, or other special provisions. Capstone, et al. suggests that if a customer with distributed generation can enter into an arrangement specifically relieving the utility of the obligation to provide standby power at certain times, such as during peak load, then that customer should not be charged a standby rate that assumes the customer would require service at system peak.

Capstone, et al. opposes utility arguments that anything short of physical assurance will not provide the certainty the utility needs to build or reserve less distribution infrastructure than the customer's full potential demand. Capstone, et al. maintains there are types and levels of assurance, other than physical assurance, that offer different values to the utility and can provide sufficient certainty.

5.12 Cogeneration Association of California/ Energy Producers and Users Coalition

CAC/EPUC state that in designing standby rates, the Commission should be guided by the principle of cost-causation and require that a customer only be assessed charges for those costs that the customer caused the utility to incur on his behalf. In this context, the cost-causation principle requires that the diversified demand of all standby customers as a class must be taken into account in passing through any transmission and distribution charges to standby customers.

CAC/EPUC urge the Commission to adopt standby rate design policy with five primary characteristics. First, the standby rate should accurately reflect the expected diversified demand of all customers taking standby service. Historically, standby rates in California have accounted for the diversity of the standby customer class. CAC/EPUC asserts that the utilities do not dispute the need to account for class diversity in the standby rate, the only disagreement is quantitative, i.e. the level of diversity for each individual utility at the distribution and transmission level. CAC/EPUC state that if the utilities do not take class diversity into account in this manner, federal law affecting standby rates for qualifying facilities would be violated.

Second, the rate design should allow for separately assessing charges for maintenance and backup power. Supplemental power is no different from the service provided to a full-requirements customer and may be priced at the same rate. In contrast, maintenance power is power supplied by the utility to replace the generation from distributed generation facilities when the facilities are scheduled out of service for maintenance. Maintenance power is provided on a pre-arranged scheduled basis and is only required for short durations. Since the supply of maintenance power can be arranged at a time when the utility has idle capacity available, the utility will not need to plan for or add capacity to meet maintenance power demand. This characteristic should be reflected in the rate paid for this power. Similarly, the payment for backup service should reflect the cost imposed on the system by distributed generation equipment of different characteristics. CAC/EPUC maintains that there should be a separate charge for each of these services due to their unique cost-causative characteristics.

Third, the standby tariff should be a stand-alone tariff in order to ensure that diversity is taken into account, that maintenance and backup service are assessed charges according to the cost-causative characteristics of those services, and to avoid excessive metering costs. For, example, SCE's proposed Schedule S would require dual meters for load and generation in place of the current single meter configuration. This is an unnecessary cost for customers who only purchase standby service.

Fourth, Standby rate design should allow customers to elect a standby reservation capacity. The elected capacity should be the basis for a minimum monthly charge paid to the utility.

Fifth, customers should have the option of firm or interruptible service. Customers who select interruptible service should be assessed a lower rate to compensate them for their willingness to accept standby service at a lower level of reliability.

5.13 City and County of San Francisco

CCSF generally supports the position of the State Consumers and states that the Commission should endeavor to reduce the need for transmission and distribution upgrades by supporting a healthy customer-side distributed generation market. CCSF further states that bundled energy prices for standby service are anti-competitive in a post-transition economy. CCSF asserts that standby costs are "so minimal that they are within the noise level of planning for the UDCs". (CCSF Opening Brief-Phase 2, p. 7.) CCSF also states that diversification of distributed generation resources will counteract the need for 100% standby service. The need for standby service must factor in the probability that a distributed generation unit outage will contribute to the incurrence of costs on the distribution system. The cost to the utility of standby power will be a factor of the overall level of diversity of distributed generation units in the system as well as the reliability of distributed generation units. By reducing barriers to distributed generation deployment such as standby charges, distributed generation investments will grow and help to defer the cost of new distribution capacity. CCSF claims that any method that can defer new distribution capacity, such as distributed generation deployment, will help to decrease costs. CCSF further claims that these decreased costs must be accounted for in the formulation of standby costs.

6. Major Issues

6.1 Nature of Costs to Serve Standby Customers

As a matter of policy, most parties agree that standby rates should be cost-based. PG&E, SCE, and SDG&E believe that most of the costs associated with providing T&D services are fixed and recommend that these costs be recovered through fixed charges. SCE testimony notes that "in designing rates for distributed generation customers, similar to other customers, it should be recognized that there are some distribution costs that do not vary with the volume of customer usage delivered through the utility's T&D system and these costs cannot be avoided when customers install distributed generation. Standby rates should ensure that distributed generation customers pay these unavoidable costs, but are given appropriate credits in their standby demand charges in recognition of their reduced demands on the distribution circuits resulting from their deployment of distributed generation." (SCE: Ex. 71, p. 6.)

SCE also states that "it is beyond dispute that a portion of distribution costs is fixed in nature", and that the costs of certain distribution assets do not vary depending on usage. (SCE Opening Brief-Phase 2, p. 22.) For example, SCE states that the cost of maintaining a meter or pole does not vary depending on how much energy a particular customer uses. It is these types of costs that SCE argues should be recovered according to cost causation principles whereby each customer pays a fixed charge to recover the costs incurred on its behalf. Other costs, such as for transformers, do vary depending on usage and their recovery through variable, usage-based charges would be appropriate. (SCE Opening Brief-Phase 2, p. 22.)

TURN disagrees, and points out that there are some costs associated with providing T&D service that are not fixed and that do vary with usage. TURN points to the testimony of SCE witness Jazayeri where he states that costs that are kilowatt-demand related vary with customer usage as support for its position. (TURN Opening Brief-Phase 2, p. 24, citing RT 1290.) TURN takes the position that fixed charges are not consistent with cost causation on the distribution system over the long term. Capstone, et al. maintains that distribution costs vary with customer usage. (Capstone, et al. Opening Brief-Phase 2, p. 10.)

6.2 Types of Standby Service

When a customer installs an onsite generator, the customer may chose to interconnect that generator to the grid. Today, all interconnected generators that do not qualify for net metering or other exemptions, whether serving as a primary or backup power source, must pay standby charges as a function of interconnecting with the grid. However, customers frequently use their onsite generators for different purposes and desire different levels of service. Today, utilities offer three general types of standby service: supplemental, backup, and maintenance.

CAC/EPUC request that the distributed generation customer be able to elect and adjust its reservation capacity for various standby services. CAC/EPUC recommend that the tariff include a reasonable, but not excessively punitive, monetary penalty for exceeding the elected reservation capacity.

CAC/EPUC is opposed to contract capacity ratchets such as those in PG&E's Schedule S.

PG&E's Schedule S allows new distributed generation customers to elect their reservation capacity. However, if the customer's demand exceeds the contracted capacity in any billing month, that demand level becomes the new reservation capacity for 36 months. PG&E states that the 36-month ratchet provision is necessary to allow the utility to make necessary planning adjustments to meet the increased standby demand level. Under SDG&E's Schedule S, the contract demand level is determined by customer's Generation agreement. If the customer takes service in excess of its contract demand in any billing month, the increased demand shall become the new contract demand for a 12-month period. Under SCE's Schedule S, the level of standby demand is the lower of the nameplate capacity of the customer's alternate power source, or SCE's estimate of the customer's peak demand.

Supplemental power is supplied by the utility to a customer whose onsite source of generation does not regularly supply all the power necessary at their premises. Currently, supplemental power is priced according to the customer's otherwise applicable tariff, but under a separate tariff. Customers take supplemental power when the installed capacity of their onsite generator does not supply their full load. For example, a customer whose demand is 4 MW who installs a 3 MW generator would have a supplemental power load of 1 MW.[15] Likewise a customer whose generator serves as a backup power source and thus the customer normally relies on the utility for power is a supplemental power

[15] The 3 MW load normally served by onsite generation would take backup standby service.

customer. By its nature, the utility must plan to serve supplemental power loads. The utilities recommend that supplemental power be priced according to the customer's otherwise applicable tariff rate. CAC/EPUC concur with this recommendation.

Backup service is supplied by the utility in lieu of generation normally provided by the customer's onsite generation facilities during periods of unscheduled outages. Backup service is available instantaneously and effectively requires the utility to reserve capacity to serve the backup load at all times. The utility must plan to serve the load of backup customers. In some respects, backup service is similar to supplemental service.

Currently the energy charges on PG&E's Schedule S are differentiated by peak, partial-peak, and off-peak periods and summer and winter seasons. When a customer's distributed generation unit suffers an unscheduled outage, the customer pays for backup power based on the time and season when the outage occurs. For customers with unscheduled outages, SCE backup charges are based on the otherwise applicable tariff, except that instead of the otherwise applicable tariff's peak demand charge, backup customers under Schedule S pay the standby demand charge. SDG&E's Schedule S is used primarily by QFs in combination with the otherwise applicable tariff, such as Schedule AL-TOU. The tariff combination provides reduced demand charges for backup and maintenance service compared to demand charges the customer would otherwise pay on the otherwise applicable tariff. SDG&E emphasizes that Schedule AV-1, not Schedule S, is the tariff applicable to distributed generation installations.

Maintenance service is scheduled by the customer with the utility to replace onsite generation when the customer's generating facilities are scheduled to be out of service. Unlike backup service, maintenance service is scheduled with the utility at times of low load and thus does not require the utility to build or reserve capacity to serve it.

PG&E does not offer an additional reduction or incentive for customers to schedule maintenance with the utility beyond the time differentiated backup schedule. Customers taking backup service under PG&E's Schedule S can schedule maintenance during the lower cost periods. Once a customer whose otherwise applicable tariff includes a time-related demand charge has been on SCE's Schedule S for six months, the added demand created by scheduled maintenance may be ignored for purposes of determining the standby demand charge. The customer continues to be responsible for the generation reservation charge from Schedule S as well as all applicable charges from the otherwise applicable tariff. This exclusion applies to one outage per year, as long as the outage is scheduled with SCE. All other charges continue to apply. When a customer on SDG&E's Schedule S schedules a maintenance shut down of its generating facility, the on-peak demand charges on its otherwise applicable tariff are waived up to the contracted standby level.

CAC / EPUC request that separate incentives be offered for maintenance service or scheduled outages that would be credited against the standard backup standby rates to lower the customer's total cost. PG&E and SCE state that they already offer separate, lower-cost options for maintenance power since maintenance power can be scheduled over weekends and during the winter season when the volumetric components of the rate are significantly lower. They do not believe any further incentive for scheduled maintenance is necessary or required.

6.3 Diversity and Reliability

Transmission and distribution costs associated with standby service are related to two key factors: the overall level of diversity among individual customer loads on the system, and the reliability of the customer's generating facility. The level of diversity among individual loads defines the total amount of load placed on the system by a combination of users. The parties all agree with the basic premise that diversity levels represent a statistical assumption that a certain percentage of standby load will be utilizing transmission and distribution service at a particular time. All but one of the parties taking a position on standby issues either supports or is not opposed to the concept of taking diversity into account when establishing standby rates at transmission and distribution voltages. The only party to dispute the applicability of diversity factors to standby customer load is the CA ISO.

SCE states that its proposed post-transition standby rate structure fairly accounts for diversity. SCE agrees that reliable distributed generation will place less demand on the system, and supports applying a diversity factor adjustment based on system-wide averages. SCE's current diversity factors are estimated using a sample of large standby customers with generation metering taking service on Schedule S. The generators owned by the sample customers are relatively large and are expected to be more reliable than smaller generators, resulting in a more diversified back-up load.

PG&E also states that the diversity of standby load is relevant, but argues that it is relevant only to the extent that it results in real savings to the utility. PG&E recommends that each utility separately calculate a diversity factor for customers taking standby service at transmission and distribution levels. That factor should reflect the extent to which generation diversity permits the utility to avoid building system upgrades. In addition, PG&E requests that the Commission find that its current diversity factor requires adjustment.

PG&E's experience at the transmission level demonstrates that the diversity of generation supply at transmission level and the networked nature of the transmission system can permit the utility to avoid building some capacity that would otherwise be needed. However, radial distribution lines operate quite differently than networked transmission lines, and, in PG&E's opinion, the small quantity of distributed generation on the distribution lines does not support a distribution level diversity discount at this time. PG&E agrees that at some point, after enough distributed generation units are installed and operating on a radial distribution line, distributed generation units could provide a level of reliability sufficient to allow the utility to avoid building new distribution capacity.

SDG&E is not opposed to standby rates that reflect diversity and reliability factors. SDG&E agrees that diversity exists on a networked system, such as the transmission system, because power can flow in multiple directions. However, due to the radial design of the distribution system, SDG&E argues it is impossible for units on one circuit to provide diversity to a different circuit. SDG&E contends that until there are multiple distributed generation units on any given distribution circuit, it is inappropriate to assume any diversity value from distributed generation for that distribution circuit.

SDG&E provided the following example. Assume there are two distributed generation units on a utility's distribution system and each distributed generation unit is located on a different distribution circuit. If one unit is never off and the other is never on, it makes no sense to average the two outage rates and assume there is a 50% likelihood that both units would be online. SDG&E argues that, in this example, the outage rate of one unit is irrelevant to the outage rate of the other unit. (SDG&E Reply Brief-Phase 2, p. 14.)

Sierra agrees that it may be appropriate to apply a diversity factor to lower the costs associated with serving standby customers, since not all standby customers will require backup at the same time. However, Sierra emphasizes that diversity factors should only be applied where there will be cost savings for the utility, such as a reduction in the amount of capacity need to provide backup service.

ORA, TURN, CAC/EPUC, Capstone, et al., Enron, FEA, State Consumers, and Aglet all maintain that reliability and diversity are important characteristics of distributed generation that should be reflected in standby rates. As additional distributed generation units are located on the transmission or distribution system, the diversity of these units will lead to a lower amount of additional standby capacity needed to serve standby loads. These parties suggest that greater diversity of the load of the individual distributed generation facilities should be reflected in lower standby rates.

FEA argues that existing standby rates do not adequately reflect the outage characteristics and range of reliability of generation facilities. FEA suggests that one method to reflect varying degrees of diversity and reliability is to apply an on-going standby reservation charge that reflects costs at a level similar to costs imposed on the system by distributed generation with a high degree of reliability. FEA observes that this methodology has been considered primarily in the context of transmission and generation requirements, but could also be applied to standby distribution service. To reflect lower levels of reliability, higher amounts would be charged for actual standby usage when outages occur. For example, a standby reservation charge might reflect costs associated with a 5% outage rate, provide an ongoing revenue contribution, and provide standby at a minimum level. If a distributed generation facility has an outage rate greater than 5%, increasing amounts of standby usage charges would be levied based on actual use on a per kWh basis. FEA does not propose a specific method to have these characteristics reflected in rates; instead, FEA requests that the Commission institute a separate proceeding to consider the design of standby rates.

ORA takes the position that the utilities should base standby charges on the full cost of serving firm loads, but should not assume that they must be able to serve 100% of standby loads at any particular time. ORA states that, currently, for purposes of evaluating distribution system requirements, the utilities assume that distributed generation or self-generation units are not operating during the peak hour. ORA believes that the utilities' approach to distribution planning may overstate standby capacity requirements and lead to unnecessary investments in distribution facilities in certain instances because it ignores the low probability of multiple outages of self-generation units. ORA contends that while the utility may be justified in assuming that a single distributed generation unit will be out of service during the peak hour and installing standby capacity to serve that unit, there is only a small probability that multiple distributed generation unit outages will occur simultaneously. ORA suggests that the utility need only build to cover the capacity of the largest distributed generation unit in each Distribution Planning Area (DPA).

PG&E criticizes ORA's proposal as having the potential to substantially impair distribution reliability. PG&E states that its distribution system is operated through approximately 200 DPAs containing over 3,000 circuits. Each circuit contains many individual distribution lines. Unlike the transmission system, which is networked, most of the distribution system is radial in nature. According to PG&E, if there are 20 distributed generation units in a DPA, each on a separate radial circuit, the utility will need to build enough distribution capacity to meet the load of every one of the generators taking standby service, not just the largest one. Capacity on the radial line serving the largest unit in the DPA will not help meet load on other radial lines in the DPA.

Indeed, PG&E argues that even when there are *two* distributed generation units on the same circuit, the utility will need to build enough capacity to meet the load of each. PG&E uses the following example. Assume the utility has a radial line with 4 MW of load not served by distributed generation, and two 1 MW load customers, each served by a 1 MW distributed generation unit. Absent clear proof that both plants will never be out at the same time, PG&E argues the utility will need to build enough capacity to serve the entire 6 MW.

CAC/EPUC remind us that the statistical probability that different individual customers in the standby class will require standby service at the same time (the coincident peak) may be estimated. Using this estimate, the utility needs only to plan for that level of coincident peak demand. CAC/EPUC request that the Commission reaffirm in this decision the principle of assessing charges to standby customers on the basis of the coincident peak of the class.

PG&E believes that CAC/EPUC's basic premise is flawed because there is not one "coincident peak" associated with the distribution system. PG&E contends that the "distribution system" is not one system, but the sum of over 200 different distribution planning areas, comprised of over 3000 circuits. Many of these areas do <u>not</u> have coincident peaks that coincide with each other, or with the system peak. However, even if they did, PG&E argues that it would be irrelevant, since the existence of a generator on a north coast circuit would have no impact on distribution costs in the central valley, even if the two happened to peak at precisely the same time.

Like ORA, CAC/EPUC, Enron, and FEA, TURN disagrees with the utilities' claim that they must plan and reserve capacity to serve 100 percent of the standby load. TURN believes that the diversity of standby load must be incorporated into the design of standby rates. TURN suggests that utilities' concerns regarding the need to know with certainty that a distributed generation unit will be operating at times of peak demand can be remedied if customers provide physical assurance. TURN also suggests that customers taking standby service have their distribution tariffs adjusted based on the reliability of the distributed generation unit. TURN suggests that such reliability adjustments could be done on a technology-specific or project specific basis.

CCSF suggests that PG&E's analogy of a fire department's need to have equipment beyond that needed to fight just one fire at a time is an accurate comparison to the situation of standby service. (CCSF Reply Brief-Phase 2, p. 2.) CCSF states that it is true that a fire department must plan for the possibility that two or more fires will occur simultaneously, but the fire department does not need a fire truck to standby for every building that might catch fire. Just as the fire department must plan for, PG&E must undertake similar planning activities and plan for the probability that a distributed generation outage will contribute to the occurrence of costs on the distribution system.

CAC/EPUC points out that historically, standby rates in California have accounted for the diversity of the standby class. CAC/EPUC state that the utilities do not dispute the need to account for diversity in the standby rate, the only disagreement is quantitative, i.e., the level of diversity for each individual utility at the transmission and distribution level.

6.4 Should Distribution Costs be Recovered through Fixed or Variable Charges?

The parties have diametrically opposite views as to whether distribution costs to serve standby customers should be recovered through fixed or usage-based rates. The utilities contend that a reservation charge is necessary to compensate the utility for the fixed, ongoing cost of reserving capacity on the T&D system whether or not this service is used. The utilities argue that reservation charges should reflect the fact that a portion of the system is being held available to provide this service.

TURN, ORA, FEA, Capstone, et al., State Consumers, and Enron all propose that the Commission adopt usage-based charges. TURN states that fixed reservation charges to recover distribution costs will discourage the use of distributed generation, stating that the presence of large fixed costs will deter acquisition of distributed generation even when such use would be economically efficient. TURN recommend usage-based, volumetric charges to provide an incentive to reduce usage. ORA also disagrees with the utilities' position, and argues that reservation charges can be a barrier to an economically viable distributed generation market if those charges are unreasonably high. Capstone, et al. is concerned that tariffs insensitive to changes in customer usage will foreclose customer opportunities to reduce their bills by changing their behavior or usage patterns. Capstone, et al. maintains that since distribution costs vary with customer usage, usage-based pricing is the fairest and most efficient way for utilities to recover both fixed and variable costs associated with distributed generation and to reflect the costs of expansion.

Both Capstone, et al. and FEA suggest that shifting away from fixed-type charges that are insensitive to usage toward usage-based charges encourages demand-responsive behavior, and need not compromise the objective of cost-based charges. FEA also asserts usage-sensitive standby charges will facilitate the development of distributed generation by charging rates more consistent with the cost of providing service.

State Consumers propose three standard tariff options: usage only, usage and reservation fee, and reservation fee only. State Consumers also propose contracts for tailored standby rates between the utilities and their customers. Enron proposes two options: reservation fee only, and usage only rates. These parties did not provide any additional details regarding how these rates should be structured. Enron and State Consumers also propose options for backup standby service that recovers some distribution revenue from reservation charges and some from usage charges. The utilities oppose the optional rates described because they argue they do not provide accurate price signals to customers.

ORA and FEA support time-of-use demand charges that reflect the cost of providing service during various times of day or seasons. ORA notes that the utilities have designed current TOU definitions to be compatible with daily and seasonal variability of energy and generation costs. ORA suggests that the Commission should consider changing current time of use definitions to be more compatible with distribution systems costs. PG&E, SCE, and SDG&E all oppose TOU on the basis that there is no direct link between TOU usage shifts and distribution facility cost savings, and the system average TOU rates cannot capture the wide variation in peak load times in various distribution planning areas.

Currently, the energy charges associated with the otherwise applicable rate schedules used by the utilities in conjunction with their standby tariffs do not include commodity charges. SCE's and SDG&E's "energy charges" recover transmission, distribution, public purpose and other nonbypassable charges on a per kWh basis, but do not actually include energy commodity charges. PG&E's "energy charges" also recover transmission, distribution, public purpose and other nonbypassable charges, however, PG&E's Schedule S, when used as a stand-alone tariff by those customers whose distributed generation units do not exceed their load, also contains energy commodity charges.

FEA points out that standby service requires the use of generation, transmission and distribution facilities. On an unbundled rate basis, FEA presumes that the generation component will be contracted for in the marketplace, the transmission component will be contained in FERC-approved rates, and that the distribution component will be included in the rates approved by this Commission.

6.5 Should Standby Rates Reflect Embedded or Incremental Costs?

The parties have differing views as to whether distribution costs to serve standby customers should reflect embedded or incremental costs.

SDG&E states that a standby charge that reflects the incremental cost of distribution assets to provide service to distributed generation is inappropriate because it fails to address the full cost of providing service to the whole customer. (SDG&E: Ex. 72, Appendix A, p. 3.) SCE states that "charges for standby service should be based on the marginal cost of serving standby customers scaled to the utility's revenue requirement, consistent with retail rate design for other services provided by the regulated utility. Current standby rates are based on the marginal cost of providing T&D services to retail rate groups, which include both full service and standby customers. (SCE: Ex. 71, p. 19.) PG&E states that to the extent possible, standby charges for distribution should be based on the same marginal cost-based ratemaking consideration used for all other retail rate classes. (PG&E: Ex. 73, p. 14)

FEA believes that if embedded costs are used to develop full requirements rates, embedded costs should be used to develop standby rates. Similarly, if marginal costs are used for the full requirements rates, marginal costs should be used to develop standby rates. Aglet's position is that standby charges should recover fixed and variable costs of providing standby service. Aglet supports determination of standby charges based on embedded, not incremental costs of service, consistent with the manner in which rates are calculated for other distribution services. State Consumers take a different position and recommend adopting incremental marginal cost pricing and cost causation allocation methods for each component of standby charges.

State Consumers support area-specific marginal cost pricing for standby rates. Capstone and NRDC join State Consumers in recommending that standby prices be linked to the utility's individual distribution system planning areas to reflect area-specific investment rather than system-wide investment. According to these parties, standby customers require minimal distribution system additions and would induce no additional costs in a DPA that is uncongested.

FEA does not support standby rates reflecting geographic distinctions unless the same methodology is used to determine rates for full requirements customers. The utilities do not support area-specific standby rates under any circumstances. PG&E asserts that while localized distribution rates might send more accurate price signals for customers, it cannot rely on price incentives alone to ensure adequate capacity is available to serve load. PG&E and SDG&E prefer individual contracts with physical assurance provisions to localized rates. SCE cautions against a piecemeal introduction of localized rates. All utilities claim that averaging utility rates across a service territory fairly spreads the costs of system improvements to all customers.

6.6 Transmission Charges/Gross Load Metering

ORA recommends that standby customers have the option of taking service at either distribution or transmission voltages, as they do today, with appropriately differentiated cost-based rates for each service.

State Consumers urge the Commission to advocate before FERC for marginal cost pricing for the transmission component of standby rates. Use of marginal cost-based transmission charges would accommodate transmission-related discounts where distributed generation can reduce line losses and help meet local reliability needs through provision of reactive power and voltage support. Discounted standby rates would serve as a proxy until the ISO either implements competitive procurement or pays distributed generation providers on a contractual basis for ancillary services.

State Consumers and CAC/EPUC support further unbundling of the transmission component of standby service. Both oppose the ISO's proposed policy to meter the gross loads of distributed generation customers and charge the ISO Grid Management (GMC) and Transmission Access Charges (TAC) for gross load even if the load is partially or entirely met by on-site distributed generation. State Consumers assert that only costs associated with a distributed generation customer's load taking energy from the grid should be reflected in standby rates. State Consumers assert that the Commission should enforce the mandate of Pub. Util. Code § 372(f) to "undertake all necessary efforts to revise, mitigate, or eliminate the policy or action of the ISO that unreasonably discourages cogeneration or self-generation." State Consumers assert that the ISO's gross load metering policy is exactly the type of "unreasonably discouraging" policy or action that § 372(f) was designed to address. State Consumers urge the Commission to file a position at FERC protesting the ISO's gross metering proposal

6.7 Interruptible or Non-Firm Standby Rates

Non-firm standby service would interrupt distribution service to customers during periods when load on the associated distribution circuit is constrained. Enron, CAC/EPUC, Capstone, et al., ORA, FEA, and TURN all propose that non-firm options be offered for backup standby service. None of these parties evaluated any of the current interruptible standby options offered by the utilities. Nor did any party offer specific recommendations for designing this type of option.

ORA indicates the utilities should have no responsibility to include non-firm standby demands in the forecasted peak loads of their resource plans. ORA states that customers would have to accept energy delivery on an interruptible or as-available basis, and in return, the utilities could eliminate reservation charges for non-firm service.

Both PG&E and SDG&E currently offer varying types of non-firm standby services. SDG&E is willing to continue its interruptible program; PG&E has proposed to eliminate the non-firm option in its pending GRC application, since non-firm programs have typically related to provision of generation service. PG&E indicates that non-firm service options for distribution service would be possible provided the discount accurately reflects cost savings and PG&E could rely on the customer's curtailment.

PG&E's current non-firm standby service is contained within its standby tariff. Customers who choose non-firm standby service under Schedule S must have at least 500kW of average peak-period on-site load, participate in PG&E's emergency curtailment program, maintain a communication channel from the customer's facility to a PG&E control center, and be subject to pre-emergency and emergency curtailments each year. Customers who do not curtail upon request are subject to a penalty over and above the regular charges. PG&E provides bill reduction credits for curtailment during on-peak and partial peak periods, and an additional credit for customers who participate in the Under Frequency Relay program.

SDG&E offers two interruptible standby services. The first service is offered primarily through its Schedule AV-1, a general service, time-of-use tariff most commonly selected as the otherwise applicable tariff by distributed generation customers on Schedule S-Standby tariff. Schedule AV-1 allows customers with or without on-site generation to choose whether or not to shed peak load in response to an electronic signal notification by the utility. The utility typically signals customers when SDG&E's system load reaches peak levels, or when either the utility or the ISO calls a Stage 2 or Stage 3 emergency. The customer may choose to pay higher peak prices or curtail load. SDG&E states that customers achieve bill savings on AV-1 as a result of lower prices in all periods other than the signaled peak, and the fact that there is no on-peak demand charge associated with Schedule A-V1.

SDG&E's second interruptible standby option is offered through Schedule S-I *Standby Service-Interruptible*. This tariff allows customers with total load over 500 kW to avoid the minimum charge provision of their applicable tariff, Schedule AL-TOU, and the costs associated with the peak load being curtailed. Curiously, SDG&E's current Schedule AL-TOU does not have a minimum charge rate component, so it appears the benefit of the waived minimum charge in Schedule S-I is already conferred in Schedule AL-TOU. SDG&E requires a customer on Schedule S-I to install a circuit breaker with remote control capability for the utility to disconnect interruptible load during periods of curtailment. Customers on Schedule S-I receive a thirty-minute notification prior to interruption, and must drop load during interruption periods. There are currently no customers taking service under Schedule S-I.

SCE recommends that the Commission reject proposals for non-firm or interruptible standby rates. SCE states that the majority of distribution costs are fixed and are not avoided when the customer provides the utility with the right to curtail its load at the time of a shortage of distribution capacity. Moreover, SCE states that, due to the limited number of participating customers on each circuit, the utility would need to have physical assurance that these customers will not impose backup load on the distribution circuit at the time it peaks. Traditional penalties such as high "excess energy" charges will not be sufficient to ensure the reliability of the distribution system.

PG&E also opposes any future requirement to provide non-firm standby and states that future non-firm service options for distribution would only be possible provided that the discount accurately reflected the cost savings and that PG&E could rely on the customer's curtailment. PG&E argues that price incentives, by themselves, do not provide the assurances required to ensure sufficient capacity is available to serve the load. In addition, PG&E states that it is unaware of how the physical details of the hypothetical non-firm standby service would work, or what the physical steps would cost. The facilities necessary to make sure that the load never draws on the utility during peak hours have not yet been designed or tested.

6.8 Valuation

R.99-10-025 questioned whether a valuation methodology should be established to assign value for potential distribution benefits of distributed generation. In Phase 1 of this proceeding, parties submitted testimony on the concept of a valuation system, and whether such a system is needed.

Several parties submitted Phase 1 and Phase 2 testimony that supports recognizing certain benefits provided by distributed generation users to the distribution system. Potential benefits listed by parties include extended distribution equipment life, deferral of distribution capacity upgrades, increased supplies of reactive power and lower energy supply costs for non-generating ratepayers. In Phase 2, TURN, ORA, Joint Parties and State Consumers proposed methods to reflect these potential benefits, which included standby rate credit mechanisms and other standby rate designs, such as time-of-use rates and locational or geographic-specific pricing.

TURN did not propose a specific methodology to quantify distributed generation benefits. In general, TURN urges the Commission to direct the utilities to design standby rates that recognize distributed generation's economic benefits to encourage deployment that will produce cost savings for both utilities and customers. TURN supports a standby rate structure where customers with less reliable generators pay a higher amount for more frequent use of the distribution system. TURN further supports the concept of time-of-use standby rates that provide incentives for customers to operate distributed generation in a manner consistent with peak demand in the local distribution system.

ORA supports credits to reflect specific localized benefits of distributed generation. Joint Parties supports locational standby rate riders or credits to reflect distribution cost savings due to distributed generation installed in a given geographic area. Joint Parties indicates that the form contracts proposed by SDG&E could serve as a starting point for this approach.

SDG&E's Form Contract proposal was presented in Phase 2 as a methodology to value distributed generation benefits to the distribution system. SDG&E proposes to provide credits when distributed generation is installed to meet SDG&E's criteria: right location, right time, right size, and with physical assurance such that SDG&E is able to avoid a distribution capacity addition for at least one year. SDG&E states that since its current standby rates apply only to QFs and not distributed generation, the credits would apply to the distributed generation customer's on-peak demand charges from Schedule AV-1.

7. Discussion and Summary of Adopted Standby Rate Design Framework

In this decision, we must determine whether we should modify the Commission's existing standby rate design for customers who utilize onsite generation for some or all of their electricity requirements. We briefly review the policy goals we identified in this Rulemaking. An April 14, 2000 Ruling addressed the scope of the Phase 2 portion of the proceeding, and directed that rate design and ratemaking policies submitted in this proceeding should:

1) provide for fair cost allocation among customers;
2) allow the utility adequate cost recovery while minimizing costs to customers;
3) facilitate customer-side distributed generation deployment; and
4) send proper price signals to prospective purchasers of distributed generation.

With these goals in mind, we focus on the major issues in the standby rate design portion of the case: the nature of the costs to serve standby customers; different types of standby service; whether costs of standby service should be recovered through fixed or usage-based rates; how to reflect diversity in rates; interruptible rates; credits for reliability; and other optional rate designs such as area and/or time-specific rates. In doing so, we fulfill our goal, supported by all parties, that there be consistency in the design of standby rates for all California utilities. As we adopt policies to address each of these issues, we keep our original goals in mind, and the understanding that unjustified standby charges for onsite generating facilities will discourage development of new generating capacity. In addition, we hope that the policies we adopt will lead to clear, understandable and administratively feasible standby rates. Because the standby rates design policies we adopt herein are cost-based, and there is no evidence that distributed generation deployment will soon cause significant stranded distribution costs, implementation of these policies will not harm the utilities.[16] Thus we have not addressed the stranded cost proposals addressed in the Phase 2 testimony and briefs.

We find that most of the distribution system costs to serve standby customers appear to be fixed in nature. For example, distribution infrastructure investments are lumpy in nature. Traditional distribution system upgrades and extensions are generally installed in increments that provide system flexibility if growth exceeds projects, but could also risk over-building if load does not materialize. Typical increments of capacity needs are in the 1 MW range. (Distribution System Operations and Planning Workshop Report, p. 41.)

In comments on the proposed decision, SCE distinguishes between different types of distribution infrastructure costs. SCE describes facilities-related costs as poles and wires, which it believes are fixed and independent of usage. SCE then describes peak demand-related (or capacity-related) infrastructure costs such as substation capacity and transformation costs as variable in nature. We agree that such a distinction is useful as we discuss standby rate design. The record in the case is insufficient to determine specifically which costs are fixed and which are variable.

However, if a customer is willing to provide physical assurance, it is clear that both facilities-related and peak demand-related infrastructure costs associated with serving that customer will either be very limited or nonexistent.

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[16] Parties generally agree that to the extent that DG customers pay their fair allocation of the costs they impose on the system, stranded costs will be minimized. The costs of plant dedicated to providing standby service to DG customers are not stranded costs.

By agreeing to provide a physical control to remove load if its distributed generation unit is not operating, the utility does not need to build either type of distribution infrastructure to serve that customer, thus avoiding fixed costs. When a customer is willing to provide physical assurance to the utility, that customer should not have to pay for any facilities or peak demand-related costs associated with distribution service and should have the ability to opt out of standby service entirely or only take maintenance or non-firm service on a volumetric basis. In comments on the proposed decision, SCE argues that physical assurance alone will not allow the utility to avoid facilities-related costs unless the customer commits that load normally served by its own generator will drop if the generator trips. As we described in footnote 2, our definition of physical assurance incorporates just the concept described by SCE as an additional requirement above and beyond physical assurance. Therefore, we see no need to add additional language to this requirement as recommended by SCE.

State Consumers argue in their comments on the proposed decision that we should allow for financial penalties, rather than physical assurance, to ensure that distributed generation is in place during peak periods. State Consumers argue that financial penalties have long been recognized as appropriate to support performance of contract provisions. State Consumers argue that the cost of equipment to accomplish physical assurance could make a distributed generation investment uneconomic. We disagree. As pointed out by both PG&E and SDG&E in reply Comments, recent experience with the utilities' interruptible programs shows that customers may choose to pay a penalty, rather than curtail load, absent physical assurance. Our decision to require physical assurance derives from our balancing of the cost impacts associated with requiring physical assurance, against the possible impacts associated with non-performance under the "no physical assurance" scenario. If a generator without physical assurance does not perform and no facilities are in place to handle that load (as would be appropriate based on the rate design principles we adopt today), the distribution circuit can overload resulting in outages and possible property damage. We are not prepared to take this risk and thus require physical assurance for customers to take advantage of reduced standby rates.

In cases where a customer opts out of standby service or takes only maintenance or non-firm service, the customer should be able to enter into a contract, similar to SDG&E's Form Contract 2 (see Ex. 72, Attachment 2) to specify the capacity for which it will provide physical assurance.[17] As suggested by SCE in comments, the Form Contract should address proper remedies for failure to perform, but we will not specify such provision today. As suggested by PG&E, the Form Contract should establish a minimum notification period before which physical assurance devices could not be removed. The customer should not pay standby charges designed to recover the facilities- or peak demand-related costs associated with distribution service for the amount of capacity it provides to the utility with physical assurance. Because a customer does not cause infrastructure costs to be incurred when it provides physical assurance, it is consistent with cost causation principles that it not be charged for infrastructure costs.

If a customer is not willing to offer such physical assurance, the utility must construct infrastructure or continue to operate existing facilities to ensure that load from a customer taking on-demand backup service can be served.

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[17] We do not adopt Form Contract 2 at this time because it will require adjustments as a result of this decision. The utilities should file proposed form contracts with the rate applications ordered herein.

Therefore, it is appropriate for those costs to be recovered from backup customers.

Different Types of Standby Service

CAC / EPUC contend that different types of service impose a different set of costs on the utility and that these separate costs should be reflected in the standby rate design. Since supplemental power provided to customers with distributed generation is no different than power provided to a customer without distributed generation, we agree that there is no policy reason why supplemental power should be priced differently than full requirements power. We recommend that supplemental power continue to be priced according to the customer's otherwise applicable tariff.

We agree with parties such as CAC / EPUC and FEA, who request that standby rates appropriately reflect reductions in the cost of providing services such as backup and maintenance service when these reductions occur. By contrast, there will not be cost reductions related to supplemental service. In order to recognize the cost difference that may sometimes exist between supplemental power and backup power needs, we will require that the utilities reflect any actual diversity in the standby reservation charges, as discussed below. Unlike supplemental power or full requirements service, service associated with backup and maintenance power is intended to be intermittent in nature. Backup service should be allocated a greater share of costs than maintenance service because it is an on-demand service and has distribution infrastructure requirements associated with it.

Maintenance service is arranged at a time when capacity is already available, so the utility will not need to build either facilities-related or peak demand-related infrastructure to meet maintenance power loads assuming the customer provided physical assurance. This characteristic should significantly reduce the amount of fixed costs allocated to support maintenance service, thus reducing the reservation charges. While utilities must plan for and reserve transmission and distribution capacity to meet supplemental load at all times, it is not necessary to reserve the same amount of capacity to meet backup loads. As SCE clarifies in its comments on the proposed decision, a maintenance customer will also avoid peak demand-related costs.

We share the parties concern regarding the need to be able to identify and elect backup reservation capacity. Distributed generation customers are in the best position to determine how much backup reservation capacity they are likely to need. The parties are concerned that utilities may overestimate the necessary backup reservation capacity for standby customers. If a distributed generation customer has underestimated the necessary backup reservation capacity, and relies on the grid in excess of its reservation capacity in a given billing period, the reservation capacity should immediately be adjusted to reflect this increase. Because of the length of time needed for planning and construction of distribution capacity, the increased backup reservation capacity should remain in effect for at least a year, unless there are further increases.

While it is clear that the utility must supply all of a full requirements customer's expected demand at all times, it is also clear that the utility must only supply a standby customer with backup and maintenance power occasionally, since the standby customer supplies its own requirements most of the time. PG&E's witness agrees that the diversity on a distribution circuit can affect its distribution costs (PG&E: Pease, RT 1081) and that it is not always necessary to provide standby power 100% of the time. (Id. At 1080.) The utility would no more need to build sufficient facilities to anticipate simultaneous failure of all onsite generators than it would need to anticipate that at one moment, every lamp would be lit, every hairdryer would be running on high, and every iron would be hot.

PG&E and SDG&E raise valid concerns regarding the potential for differences in the diversity on the transmission system compared to the distribution system. However, as PG&E also points out, because there are relatively few distributed generation units connected at distribution voltage, there is virtually no diversity on individual distribution circuits today. Thus, it is reasonable that, in the near-term, each distribution utility would plan its distribution facilities without taking into account the potential benefits of onsite generation diversity. Standby rates should reflect this reality. To do otherwise would be to adopt a policy of promoting distributed generation at the expense of all utility ratepayers.

Based on the records developed in this proceeding we cannot determine whether any diversity exists for generators connected at distribution voltages. In their applications for new standby rates, the utilities should report on the extent of diversity based on actual deployment of onsite generation on the distribution system and propose a diversity factor, if appropriate.

We note that CAC/EPUC suggests that a failure to adopt a diversity factor would violate federal law. Apparently, CAC/EPUC is referring to 18 CFR 292.305(c)(1), which states that standby rates for qualifying facilities "shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously…" In concluding that diversity factors should not apply to the calculation of standby charges at this time, we make no such assumptions about system-wide generators (i.e. those connected at transmission voltages). Rather, we focus on generators connected at distribution voltages. While many distributed generators might still be operating elsewhere in the utility system, there is still a need to meet load in the absence of generation on a given distribution circuit. Standby charges should reflect the cost of providing this reliability.

Different Types of Standby Rates

There is no persuasive reason to require customers to pay for charges that are not incurred, just as there is no persuasive reason to excuse customers from paying for charges incurred on their behalf. We agree that if costs associated with maintaining distribution and transmission facilities to serve diversified standby load are fixed, those costs are appropriately reflected in fixed reservation or demand charges. We reject Capstone, et al.'s argument that fixed charges create an inefficient price signal because no action by the customer can avoid or reduce these charges. We find that if costs are fixed and unavoidable by the utility, a fixed charged is an efficient price signal. To the extent that there are costs that do vary with usage, including peak demand-related costs, those costs should be reflected in a usage-based charge.

As we analyze proposed rate design options, it is helpful to keep in mind that all parties recommend that standby rate design be cost-based. Assuming that a usage-only standby rate is intended to recover the total cost associated with providing standby service, the usage-only rate would necessarily need to recover more costs over fewer increments of usage and must therefore be set higher. Moreover, in any given month, with a usage-only fee, a customer with a distributed generation unit who required no standby service during that month would potentially pay no standby charges at all. In that month, assuming that the total fixed cost of providing distribution service does not change, the cost associated with providing standby service to that customer would be shifted to other customers. Conversely, a distributed generation customer that requires frequent standby service will contribute a significantly higher amount. Under this type of rate design, both units would pay the same rate, but distributed generation units that are more reliable would pay less than the cost to serve them. Similarly, less reliable distributed generation units would pay more for the same amount of reserved capacity. This type of rate design would result in inequitable cost allocation within the customer class.

A reservation fee only proposal would also allow customers a choice in payment terms. The reservation fee only proposals would allow customers to levelize their standby charges over an extended period of time, paying a fixed amount each month for a certain level of service. The reservation fee only proposals have appeal if one could be designed and presented in a manner that is consistent with our goal of cost-based rates. Unfortunately, none of the proposals presented in this rulemaking contained sufficient detail for us to evaluate it on this record. Therefore, we decline to consider a reservation fee only proposal at this time.

Standby rates should be designed to appropriately reflect costs imposed on the utility system by all customers, including those employing onsite generation. Ideally, a fixed standby reservation charge should be based only on facilities-related infrastructure costs that do not vary with usage. Standby customers with onsite generation who sign up for backup service should be charged a $/kW reservation charge for their reserved capacity. The reservation charge should reflect the distribution infrastructure costs that do not vary with usage. In addition, backup standby rates should include a volumetric rate, based on actual usage, that collects variable distribution costs, including peak demand-related costs. Maintenance customers and others whose use of the distribution system is on an as-available basis, should be charged a volumetric rate, based on usage, that recovers variable distribution costs but does not include peak demand-related infrastructure costs. A customer's maintenance schedule should be coordinated with the utility to ensure that its use of the system corresponds to the peaking characteristics of its distribution circuit.

Public purpose costs are collected volumetrically under current rates. We will continue to recover public purpose costs from standby customers through a $/kWh usage charge. GI/LIF, TURN, and PG&E all address this aspect of the proposed decision in their comments. These parties recommend that public purpose charges be assessed on distributed generation customers total load, including load served by an onsite generator. Our decision today is not intended to dispose of the issue of how public purpose costs should be collected from distributed generation customers, but simply to recognize that currently, standby customers pay for public purpose costs volumetrically and should continue to do so. There was extensive testimony, cross-examination, and briefing on how to ensure that all energy users pay their fair share of public purpose costs and we will address these issues on their merits in the Phase 2 order.

We are concerned that some elements of generation capacity and energy charges still remain bundled in the standby tariffs. It is in the interest of all customers, standby and full service alike, to ensure that standby charges collect only the costs associated with providing standby service. Standby rates should remove any charges not associated with providing distribution standby service. That includes any generation capacity or energy charges that may presently be bundled with and collected through standby rates. Instead, the utilities should develop an electricity procurement rate option, which may be a real time price, that will be paid by standby customers when the utility procures electricity on their behalf. If allowed under state law, standby customers should also have the option to procure electricity to serve their backup or maintenance supply from a third party.

We agree that the Commission has a responsibility to enforce § 372(f). The ISO's proposed gross metering policy has implications extending well beyond the immediate rate design of standby charges. To the extent that transmission charges recover fixed costs, they may be recovered through reservation charges. Variable transmission charges should be recovered through variable rate components. To the extent a customer with distributed generation offers physical assurance, no fixed transmission costs should be recovered from that customer. This approach should ensure the CA ISO of recovery of fixed costs without the customer burden of gross metering. Therefore, at this time, we will not support the CA ISO's gross load metering policy.

We support the concept of interruptible standby service in order to provide customers with more choices during peak periods. Standby customers willing to forego energy use during peak periods should receive the same options as customers without distributed generation. However, it is unclear how useful such an option would be to customers. Parties who support an interruptible standby option concurrently oppose the utilities' desire for physical assurance to ensure that the delivery system will not be called upon. Utility system planners would prefer a policy that guarantees customers will not demand standby during distribution system peaks. Non-firm/interruptible service taken by customers without distributed generation serves as a source of supply during times of peak load. When a customer has a distributed generation facility, it will generally be serving its own load and not relying on the distribution system. If that distributed generation customer provides physical assurance, it will not have to pay reservation charges under today's adopted policies. Non-firm standby service then becomes similar to maintenance service—load can be imposed on the system on an an-available basis at non-peak times. In comments on the proposed decision, SCE raises numerous implementation issues surrounding interruptible standby service. We find these arguments sufficiently persuasive to provide utilities the option, rather than the requirement, to develop a non-firm standby rate. The utilities may propose non-firm standby rate options that recover only variable costs of distribution service from customers who offer physical assurance.

Valuation

Without prejudging the outcome of our Phase 1 decision, we believe several benefit valuation proposals have merit and contain ideas for future consideration. In particular, we note agreement by several parties that SDG&E's Form Contract proposal could be used as a basis to determine certain incentives or credits for curtailment resulting in deferred utility distribution investment. We further agree with SDG&E that the utility should be authorized to provide credits to customers when distributed generation is installed at the right time, in the right location, of the right size and with physical assurances, such that the utility is able to defer a distribution capacity addition. However, at this time, we believe distributed generation standby service is separable from the question of whether distributed generation provides grid benefits. A distributed generation customer taking standby service may not necessarily provide measurable grid benefits. Likewise, a distributed generation customer providing grid benefits may elect not to take standby service. At the same time, we are not persuaded by TURN's suggestion that a value of distributed generation will be a reduction in wholesale electric prices. There is no evidence that, in the current market structure, lower demand will effectively reduce wholesale prices. Consistent with the schedule adopted in the January 19, 2000 Scoping Memo, we will consider the need for a valuation system of distributed generation benefits to the grid in our Phase 1 decision, and consideration of locational credits, time-of-use rates and SDG&E's Form Contracts in the Phase 2 decision.

Cost Allocation

We are not convinced that standby customers are allocated the proper share of costs on a cost causation basis. From the evidence, we cannot determine whether costs allocated to standby customers were for fixed costs associated with on-demand backup service or other services. Therefore we cannot conclude decisively whether this cost allocation overcollected revenues from standby customers, which argues for a reexamination of the allocation of costs to standby customers. In the standby rate design applications ordered herein, the utilities should review and revisit, if applicable, the costs allocated to standby customers as they develop rates consistent with this order. We agree with Aglet that standby charges should be based on embedded, not incremental, costs of service, consistent with the manner in which rates are calculated for other distribution services. We will adopt new standby rates consistent with the correct cost allocation, consistent with this order. This may result in some temporal cost recovery concerns since other distribution rates may not be adjusted contemporaneously amongst all customer classes for any new cost allocation. The utilities should propose ratemaking approaches to address any temporal inequities associated with their recommended cost allocation in the applications ordered herein.

8. Independent Clean Energy Tariff

8.1 Background

On August 21, 2000, CalSEIA filed a motion requesting expedited adoption of an independent clean energy tariff (ICE-T) to encourage electric utility customers to deploy non-polluting, renewable solar distributed generation to alleviate anticipated market supply disruptions. On August 29, 2000, the assigned Administrative Law Judge issued a ruling which denied the motion without prejudice. The ruling noted that CalSEIA served testimony proposing the ICE-T in both Phase 1 and Phase 2 of this rulemaking, and the Commission would consider adoption in this proceeding, following Phase 2 hearings.

CalSEIA would exempt solar generating facilities up to 1 MW that do not export power to the grid and are ineligible for net energy metering from any new or additional demand, standby, customer, minimum monthly, and interconnection charges, or any other charges not included in the applicable rate schedule to which the customer-generator would otherwise be assigned. [18] Because power would not be exported to the grid under this tariff, customer-generators would not be able to "bank" the value of excess generation to offset electricity taken by the customer off the grid, unless the customer entered into a power sales contract with the utility or a third party. For small installations, net energy metering tariffs achieve the removal of such technical and financial impediments. CalSEIA argues that for larger wind and solar installations that do not qualify for net energy metering tariffs, such impediments remain in place.

CalSEIA describes the ICE-T proposal as an effort to remove barriers that discourage individual customers from creating new, non-polluting generation, tailored to meet localized customer needs, and capable of being deployed quickly. CalSEIA asserts that most solar distributed generation is sized to serve on-site load only, typically to reduce peak demand. The balance of the

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[18] Net energy metering, as defined by § 2827, allows eligible customer-generators to offset usage from the grid with production by the generator through use of a bi-directional meter. Eligible customer-generators must be 10 kW or less. One provision of § 2827 is that the customer-generator's tariff schedule must assign the same rate components and charges as the tariff to which the customer would be assigned if the customer were not an eligible customer-generator. This effectively eliminates standby, demand, exit, and interconnection fees and charges for small customer generators.

customer's load is served by the utility. Cal SEIA believes the ability of solar distributed generation to remove load from the grid at system peak can make a contribution to solving California's electric market crisis, relieve local overload of transmission and distribution facilities, and provide long-term distribution system benefits, as well as overall system benefits.

CalSEIA maintains that the utilities incur minimal to no costs to interconnect solar distributed generation, therefore, no costs should be imposed on solar distributed generation customers. CalSEIA's witness testified that his review of hundreds of interconnection studies indicates that no special interconnection facilities or equipment are typically required to interconnect small-scale distributed generation to the utility system. To support its standby charge exemption, CalSEIA compares the fluctuation in demand when small solar generating facilities are installed to demand fluctuations for non-generating customers installing energy efficiency measures. In both cases, CalSEIA states that the net effect is reduced customer demand on the utility system. CalSEIA contends that utilities will not incur costs beyond those ordinarily incurred to serve demand fluctuations of non-generating customers installing energy efficiency measures.

According to CalSEIA, the current market for PV in California is about 2.2 MW per year. The market is growing at about 20% per year, resulting in an annual market of about 6 MW per year, for a total of 20 to 25 MW installed by 2006. If the ICE-T proposal is adopted, CalSEIA estimates a PV market growth rate of about 30% per year, with approximately 30 to 35 MW of PV systems connecting to the grid over the next five years. (CalSEIA Exh. 103, p. 8.) CalSEIA estimates that through 2006, solar distributed generation will still account for less than 0.1% of California's electric system peak load. (CalSEIA Exh. 103, pp. 5-6.)

ORA, NRDC, TURN, and State Consumers support CalSEIA's ICE-T proposal. TURN states that the expedited development of clean, non-polluting renewable resources should be a high priority given the current energy crisis. TURN observes that the ICE-T proposal is consistent with AB 970 and would fulfill the legislature's intent to promote rapid deployment of renewable distributed generation technologies. TURN further asserts that existing utility practices require expensive interconnection studies and impose financial hardships for solar technologies. State Consumers observe that California's net energy metering program cannot accommodate solar facilities for the type of governmental entities it represents, but the proposed ICE-T would apply to such facilities.

PG&E, SCE, SDG&E, and FEA oppose CalSEIA's ICE-T proposal, primarily on the grounds that exemption from cost-based charges is rate subsidization, and runs counter to the Commission's long-standing policies favoring cost-based rates. SDG&E and FEA assert that rate subsidies amount to poor public policy; FEA argues that subsidies promoting development or installation of non cost-effective applications will likely result in higher electric rates. The ISO does not formally oppose the ICE-T, but concurs with the utilities and FEA that costs not assessed to generators on the ICE-T would be shifted to other customers. FEA asserts that small distributed generation shouldn't be allowed to avoid costs just because the costs are small. The utilities argue that substantial federal and state subsidies already exist for solar generation.

SCE refutes CalSEIA's comparison of the demand fluctuations of solar distributed generation to those of non-generating customers installing energy efficiency measures. SCE notes that load reductions caused by energy efficiency measures such as fluorescent lighting, insulated windows or super efficient refrigerators are permanent until removed and do not require standby power, whereas solar distributed generation output can decrease due to weather conditions or nightfall. SCE argues that the benefits of solar power cited by CalSEIA and TURN are attributed to generation, not distribution, and it is not appropriate to reduce or eliminate distribution charges because of a purported generation benefit. The utilities assert that distributed generation provides benefit to the distribution system only when solicited by a utility to fulfill an identified need.

CalSEIA contends that SCE overstates the need for standby power for a technology that is almost 99% reliable, and that the demand fluctuations of small solar distributed generation are likely more predictable than demand fluctuations of non-generating customers. (CalSEIA Reply Brief- Phase 2, pp. 8-9.) TURN supports this position, arguing that solar distributed generation's unique ability to produce maximum output coincident with the customer's own peak load, near-perfect performance reliability, and reduced air emissions from peaking generators provide distribution system benefits, energy efficiency contributions, and environmental benefits to ratepayers and non-participants that should be recognized by the Commission.

8.2 Discussion

Although the Commission generally addresses issues associated with AB 970 in R.98-07-037, we are not precluded from recognizing the ability of the proposed ICE-T to promote state policy goals as expressed in AB 970. Nor are we precluded from adopting this tariff, which has been thoroughly litigated in R.99-10-025. We anticipate increased availability of and participation in renewable incentive programs such as the California Energy Commission's Emerging Renewable Buydown Program and programs resulting from AB 970 and other legislation. We agree with CalSEIA and TURN that adoption of the ICE-T will complement, rather than duplicate, existing programs for solar generation; it is consistent with incentive programs proposed to implement AB 970 and consistent with the expanded net metering program, recently approved by the Legislature in ABX 129 (Chapter 8, Stats. 2001).

Prior to this legislation, net metering benefits applied only to residential and small commercial renewable onsite generators with facilities no larger than 10 kW. Under the new law, all customer classes are eligible, and the maximum facility size is one MW. Power production above the generating customer's own needs is netted against power supplied by the utility. By law, net metering customers cannot be charged standby fees unless other customers in the customer class would also pay a standby charge. Customers without generators do not pay standby charges, and therefore, net metering customers are effectively exempt from standby charges. It is consistent with this law to exempt from standby charges those customers with similarly-sized photovoltaic installations when such customers elect, for some reason, not to employ net metering.

The ICE-T proposal targets precisely the size of customer-generator most capable and motivated to reduce peak demand: large commercial and industrial customers. According to SDG&E, most of its customers over 20 kW and all customers over 40 kW are medium or large commercial and industrial customers. (SDG&E Reply Brief- Phase 2, p. 43.) We believe these customers are also most likely to have the financial resources to pursue distributed generation options or to participate in distributed generation incentive programs.

CalSEIA has made a persuasive argument that solar distributed generation installations under 1 MW impose negligible interconnections costs on the utility system, therefore, we will waive up to $5,000 in interconnection fees for solar distributed generation up to 1 MW. Establishing such a cap, as proposed by PG&E in comments on the proposed decision, is consistent with our intent that solar generators that do not impose an undue burden in order to interconnect not pay interconnection costs. CalSEIA argues that a cap will encourage utilities to inflate costs. We do not agree with CalSEIA's assessment. Should CalSEIA observe such abuse occurring upon implementation of the cap, it should bring evidence before the Commission to demonstrate its claims and we will consider whether to remove the cap.

In all other respects, these customer-generators must comply with the interconnection requirements spelled out in Rule 21 of each utility's tariffs. Likewise, the utilities should process interconnections for these customer-generators, consistent with the requirements of Rule 21.

Based on CalSEIA's projected photovoltaic market growth, it is clear that even with extensive deployment over the next five years, small solar generating units will represent far less than one percent of California's peak demand requirements. Given that Governor Davis has called for a minimum reduction of California electricity usage of 7% from energy efficiency efforts[19], CalSEIA's comparison of solar distributed generation's impact on peak demand to energy efficiency becomes more compelling. It is well recognized that California's peak electricity usage generally occurs when temperatures are highest. High temperatures generally occur when the sun is shining. Solar generating units rely on the sun to produce electricity. It is clear that solar distributed generation, if reliable[20], will produce electricity coincident with peak demand for electricity. Thus, increased deployment of solar distributed generation will clearly provide a

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[19] Governor Gray Davis, State of the State Address, January 8, 2001.

[20] CalSEIA and TURN presented uncontroverted evidence regarding the reliability of solar DG units.

generation benefit by reducing the peak electricity demand that must be supplied by the grid. In the short term, it is less clear that distribution infrastructure costs will be avoided by installation of distributed generation. However, the forecast growth of this technology over the next five years leads us to believe that any cost shifting associated with elimination of charges not normally included in the applicable rate schedule will be very limited. Therefore, we will adopt the ICE-T for solar distributed generation units up to 1 MW that do not export power to the grid.[21]

In comments on the proposed decision, CalSEIA argues that ICE-T should not be limited to customers who do not sell power. We clarify, as TURN suggests, that customers eligible for the ICE-T should be prohibited from selling excess power but that incidental export of power to the grid should not eliminate such customer from eligibility for the ICE-T. We do not at this time expand eligibility for ICE-T to those who sell power to other users of the grid. Sales of excess energy and capacity from onsite generation to the grid raise numerous jurisdictional issues that we are not prepared to resolve in this order.

PG&E and SCE argue that adoption of the ICE-T will entail cost shifting and represents a subsidy to these customers. We disagree. Only solar distributed generators are eligible for the ICE-T. Because the sun does not shine 24-hours a day and on some days will not shine at all, customers installing solar distributed generation will necessarily take service under an otherwise applicable tariff and will be required to pay rates under that tariff that are

[21] The ICE-T is not a stand alone tariff in the traditional sense. Instead, adoption of the ICE-T means that customers utilizing solar generating units up to 1MW that do not export power to the grid will not be subject to standby charges and instead will receive service solely under their otherwise applicable tariff.

designed to recover costs of serving that customer class. If the tariff for that customer class includes a demand charge based on maximum expected demand, then the charges under the otherwise applicable tariff should fully compensate the utility for the service provided to customers eligible for ICE-T.

Several parties note the CalSEIA proposal did not include program limits comparable to the 0.1% utility system capacity limit currently in effect for California's net energy metering program.[22] SCE notes that a similar limit for solar distributed generation up to 1 MW would likely limit program availability to only a handful of large solar facilities, while without a program cap, the potential impact on remaining ratepayers could be substantial. TURN believes the 0.1% limit should apply to all solar facilities covered by net energy metering tariffs and ICE-T. With recent passage of ABX 129 (Chapter 8, Stats. 2001), the program limits on net metering have been removed, therefore we no longer need to address how participation in ICE-T and net metering interact.

9. Comments on Proposed Decision

The proposed decision of Commissioner Bilas was mailed for comment on March 23, 2001. Comments were filed by PG&E, SDG&E, SCE, ORA, TURN, CalSEIA, CAC/EPUC, jointly by Capstone and Caterpillar (Capstone/Caterpillar)), Aglet, GI/LIG,[23] State Consumers, CA ISO, and

[22] Under § 2827(c)(3), 0.1% of aggregate demand is a cap to which the utility must offer net energy metering, but the statute provides the utility with discretion to offer net energy metering to more than 0.1% of aggregate demand.

[23] On April 10, 2001, GI/LIF served an errata to its comments. Docket Office filed the errata at the direction of the Assigned ALJ.

RealEnergy, Inc. (RealEnergy).[24] Reply comments were filed by PG&E, SDG&E, SCE, ORA, CalSEIA, CAC / EPUC, Aglet, and State Consumers. We have made revisions throughout the decision to reflect comments by these parties. We note that RealEnergy and Capstone / Caterpillar recommend we delay action on this decision pending action on certain legislation. This request is opposed by SCE, PG&E, and Aglet.

On May 22, 2001, the Governor signed SB X1 28 (Stats. 2001, Chap. 12). This bill, among other purposes, directs this Commission to require utilities to charge customers that install new distributed generation under tariffs applicable to customers that do not use distributed generation. In other words, SB X1 28 exempts certain customers from payment of standby charges. A ruling directing the utilities to take steps to implement these provisions has been issued in this docket. However, given that numerous customers employing onsite generation may not be covered by the provisions of SB X1 28, standby rates will still be necessary, and the framework this decision sets forth remains appropriate for those customers, and begins the process of compliance with § 353.13 as adopted by SB X1 28. Of course, in preparing their applications in compliance with this order, the utilities should ensure that all provisions of SB X1 28, like the firewall provision, are addressed.

On April 21, 2001, the assigned ALJ received an email from Eileen Smith, representing Solar Development Cooperative (SDC).[25] The email is styled as a

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[24] RealEnergy is not listed as a party to this proceeding on the official service list but instead it holds information only status. We have however, considered the comments of RealEnergy in revising the proposed decision.

[25] An additional email was received on May 7, 2001. Copies of both emails have been placed in the correspondence file for R.99-10-025.

motion but was not filed with the Docket Office as required by our Rules of Practice and Procedure. The email seeks leave to file comments late, stating that SDC did not receive service of the proposed decision. SDC was served with a copy of the proposed decision. The mailing address on file for SDC is the same as the address listed in SDC's email. We will not grant SDC's request to late-file comments.

Findings of Fact

1. Distributed generation will provide end-users with additional choices to supply their electricity needs.

2. California is in the midst of a generation shortage, and new generation, large and small, provides substantial value in addressing that shortage.

3. Section 399.15 directs the Commission to adopt "differential incentives for renewable or super clean distributed generation resources."

4. Current standby rate design differs significantly among utilities and is quite complex.

5. Today a customer who has installed generation (either a QF or other distributed generation customer) must take standby service under one of the utility's tariffs.

6. Net energy metering allows certain customers with wind and solar facilities to avoid standby rates.

7. Physical assurance is the application of devices and equipment that interrupt a distributed generation customer's normal load when distributed generation does not operate.

8. Standby rates should be cost-based.

9. Supplemental power is supplied by the utility to a customer whose onsite source of generation does not regularly supply all the power necessary at their premises. The utility must plan to serve supplemental power loads.

10. Backup service is supplied by the utility in lieu of generation normally provided by the customer's onsite generation facilities during periods of unscheduled outages.

11. Backup service is available instantaneously and effectively requires the utility to plan to serve the diversified load of backup standby customers at all times.

12. Maintenance service is scheduled by the customer with the utility to replace onsite generation when the customer's generating facilities are scheduled to be out of service.

13. Diversity levels represent a statistical assumption that a certain percentage of standby load will be utilizing transmission and distribution service at a particular time.

14. Distribution system costs to serve backup standby customers appear to be both fixed and variable, in nature, but the record in this case is insufficient to identify specifically which costs are fixed and which are variable.

15. If a customer is willing to provide physical assurance, the utility will not install facilities to serve the load ordinarily served by the onsite generator so costs associated with serving that customer will either be very limited or nonexistent.

16. The utility must construct distribution facilities to ensure that the diversified load from customers taking on-demand backup service can be served.

17. There is no evidence that distributed generation deployment will soon cause significant stranded distribution costs.

18. Service associated with backup and maintenance power is intended to be intermittent in nature.

19. There is no standard peak period on distribution circuits.

20. Certain peak demand-related distribution costs, like substation capacity and transformation, vary with use of the system and can be avoided.

21. Maintenance service is arranged at a time when capacity is already available, so the utility will not need to build infrastructure to meet maintenance power loads assuming the customer provided physical assurance.

22. It is possible to estimate the probability of multiple distributed generation units being out of service on the same circuit simultaneously.

23. Diversity reduces transmission infrastructure requirements.

24. Diversity may ultimately reduce distribution infrastructure requirements on a given circuit; however, those benefits have not yet been demonstrated.

25. There are valid concerns regarding the potential for differences in the diversity on the transmission system compared to the distribution system.

26. Public purpose costs are collected volumetrically under current rates.

27. A distributed generation customer taking standby service may not necessarily provide measurable grid benefits.

28. Distributed generation customers providing grid benefits may elect not to take standby service.

29. Solar distributed generation installations under 1 MW impose negligible interconnection costs on the utility system.

30. Small solar generating units will represent far less than one percent of California’s peak demand requirements.

31. Reliable solar distributed generation will produce electricity coincident with peak demand for electricity.

32. Increased deployment of solar distributed generation will provide a generation benefit by reducing peak electricity demand.

Conclusions of Law

1. Rate design and ratemaking policies should:

a) provide for fair cost allocation among customers;

b) allow the utility adequate cost recovery while minimizing costs to customers;

c) accommodate customer-side distributed generation deployment; and

d) send proper price signals to prospective purchasers of distributed generation.

2. Customers should be able to enter into a contract to specify the capacity for which it will provide physical assurance.

3. Customers with onsite generation should not pay standby charges designed to recover the fixed costs associated with distribution service for the amount of capacity it provides to the utility with physical assurance.

4. It is appropriate for distribution infrastructure costs to be recovered from backup customers.

5. Supplemental power should continue to be priced according to the customer's otherwise applicable tariff.

6. Standby rates should appropriately reflect the reduced cost of providing services such as backup and maintenance service compared to supplemental service.

7. In order to recognize the cost difference between supplemental power and backup power needs, we should require the utilities to reflect diversity, where it actually exists, in the standby reservation charges.

8. Backup service should be allocated a greater share of costs than maintenance service because it is an on-demand service and has distribution infrastructure requirements associated with it.

9. Diversity factors should not be applied to distribution charges that recover fixed costs at this time.

10. The utilities should be required to separately calculate diversity factors for the transmission and distribution level interconnected generation as a result of this decision.

11. If costs associated with maintaining distribution and transmission facilities to serve diversified standby load are fixed, those costs are appropriately reflected in fixed reservation or demand charges.

12. To the extent that there are costs that do vary with usage, those costs should be reflected in a usage-based charge.

13. Standby customers with onsite generation who sign up for backup service should be charged a $/kW reservation charge for their reserved capacity.

14. The reservation charge should reflect the facilities-related distribution infrastructure costs that do not vary with usage.

15. Backup standby rates should include a volumetric rate, based on actual usage, that collects variable distribution costs, including peak demand-related costs.

16. We should continue to recover public purpose costs from standby customers through a $/kWh usage charge.

17. Maintenance customers and others whose use of the distribution system is on an as-available basis should be charged a volumetric rate, based on usage, that recovers variable distribution costs but does not include peak demand-related infrastructure costs.

18. Standby charges should be based on embedded, not incremental, costs of service, consistent with the manner in which rates are calculated for other distribution services.

19. Standby rates should remove any charges not associated with providing distribution standby service.

The utilities should develop an electricity procurement rate option, which may be a real time price, that will be paid by standby customers when the utility procures electricity on their behalf.

20. To the extent that transmission charges recover fixed costs, they should be recovered through reservation charges.

21. Variable transmission charges should be recovered through variable rate components.

22. To the extent a customer with distributed generation offers physical assurance, no fixed transmission costs should be recovered from that customer.

23. We should not support the CA ISO's gross load metering policy.

24. The utilities may propose non-firm standby rate options that recover only variable costs of distribution service from customers who offer physical assurance.

25. The diversity factor included in the unbundled standby rates we adopt today should account for lowered costs of distribution capacity deferred due to increased distributed generation deployment.

26. The utilities should review and revisit, if applicable, the costs allocated to standby customers as they develop rates consistent with this order.

27. The utilities should propose ratemaking approaches to address any temporal inequities associated with their recommended cost allocation.

28. We are not precluded from recognizing the ability of the proposed ICE-T to promote state policy goals as expressed in AB 970.

29. Adoption of the ICE-T will complement existing programs for solar generation and will be consistent with incentive programs proposed to implement AB 970.

30. Interconnection fees of up to $5,000 for solar distributed generation up to 1 MW that does not sell power to the grid should be waived.

31. Customer-generators must comply with the interconnection requirements spelled out in Rule 21 of each utility's tariff.

INTERIM ORDER

Therefore**, IT IS ORDERED** that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall file applications within 60 days of the effective date of this decision proposing standby rates that implement the policies set forth herein. Specifically, the utilities shall file applications that:

   a) propose a Form Contract for Physical Assurance;

   b) allow customers using onsite generation to pay no fixed standby charges if they sign a contract providing the utility with physical assurance;

   c) propose on-demand backup rates that recover facilities-related distribution costs through a $/kW reservation charge and variable distribution costs, including peak demand-related costs, through a $/kWh usage charge;

   d) propose scheduled maintenance rate options that recover only variable costs of distribution service, excluding peak demand-related costs, from customers who offer physical assurance;

   e) ensure that proposed standby rates separately identify any charges associated with electricity procurement;

   f) propose an electricity procurement rate option, which may be a real time price, that will be paid by standby customers when the utility procures electricity on their behalf;

   g) report on the extent of distribution level diversity and propose a diversity factor, if appropriate;

h) price supplemental power at the otherwise applicable tariff rate;

i) allow customers to elect a reservation capacity. Use by the customer in excess of the elected capacity will result in an immediate upward adjustment of the reservation capacity for a term of one year;

j) establish standby rates using embedded costs consistent with the manner in which rates for other distribution services are calculated;

k) propose standby rates that allow customers to take service at transmission or distribution voltages;

l) propose standby rates that recover fixed transmission costs through reservation charges and variable transmission costs through usage based charges;

m) reflect in the proposed standby rates that solar generating units up to 1 MW that do not export power to the grid are not subject to standby rates; and

n) collect public purpose costs from standby customers on a $/kWh usage basis, consistent with how it is collected from other distribution service customers.

o) Allocate costs to standby customers consistent with the policies adopted herein and propose ratemaking approaches to address any temporal inequities associated with the recommended cost allocation;

2. The applications may also propose non-firm standby rate options that recover only variable costs of distribution service, excluding peak demand-related costs, from customers who offer physical assurance.

3. Within 15 days of the effective date of this order, PG&E, SDG&E, and SCE shall:

a) submit an advice letter to revise Rule 21 to reflect that interconnection fees for solar generating units up to 1 MW that do not export power to the grid will be waived up to $5,000. The Advice Letter will be effective on the date filed if Energy Division finds it in compliance with this order; and

b) Notify solar generating units up to 1 MW that do not sell power to the grid that they will be served under the otherwise applicable tariffs for customers of their size and that any standby charges will no longer apply.

This order is effective today.

Dated July 12, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
RICHARD A. BILAS
CARL W. WOOD
GEOFFREY BROWN
Commissioners

I will file a written concurrence.

/s/ RICHARD A. BILAS
Commissioner

R.99-10-025
D.01-07-027

Commissioner Bilas, concurring:

At today's Commission meeting, I voted in favor of both the Proposed Decision and the Alternate Decision. The Alternate, which was successful, differed in only one respect from the Proposed Decision – the application of a diversity factor to distribution level voltages. Both the Proposed Decision and the Alternate would adopt a standby rate design policy that: 1) is consistent among all California utilities; 2) better reflects the actual cost imposed on the utilities' systems by individual standby customers; and 3) requires the utilities to include a diversity factor for transmission level voltages in the calculation of the standby charges. Both the Proposed Decision and Alternate also adopt the independent Clean Energy Tariff proposed by the California Solar Energy Industry Association. I proposed these changes and I continue to fully support them.

The only difference between the Proposed Decision and the Alternate is the application of the diversity factor to distribution level voltages. While the Proposed Decision finds that there are well-supported arguments that the presence of multiple distributed generation units on the system reduces transmission and distribution requirements and that the record supports a finding that diversity does exist on both the transmission and distribution systems of the utilities, the Alternate states that there is no diversity on the distribution system at this time. I do not believe this conclusion accurately reflects the record in the proceeding and therefore I cannot support that portion of the Alternate. I believe that the debate over specific diversity levels should be deferred to the utility-specific rate design applications.

Taken as an entire package, I support today's decision. My hope and expectation is that this action, combined with other actions taken by the Governor and the Legislature will increase the amount of distributed generation on the system and that the utilities' standby rate design applications will appropriately reflect this increase.

/s/ RICHARD A. BILAS
RICHARD A. BILAS
Commissioner

San Francisco, California
July 12, 2001