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June 2, 2003

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20462

Re: California Independent System Operator Corporation, *et al.*
Docket Nos. ER01-313-000, *et al.*

Dear Secretary Salas,

Enclosed with this transmittal letter, please find an original and fourteen copies of the Motion For Clarification, Request For Rehearing, and Motion for a Stay Pending Rehearing of The California Independent System Operator Corporation in the above captioned dockets. Two additional copies are enclosed to be date stamped and returned to our messenger. Thank you for your assistance with this matter.

Respectfully submitted,

Theodore J. Paradise

Theodore J. Paradise

Counsel for the California Independent System Operator Corporation

CC: The Honorable Bobbie J. McCartney
Service List

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	Docket Nos.	ER01-313-000 and ER01-313-001
Pacific Gas and Electric Company	)	Docket Nos.	ER01-424-000 and ER01-424-001

MOTION FOR CLARIFICATION, REQUEST FOR REHEARING, AND MOTION FOR A STAY PENDING REHEARING OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. INTRODUCTION

Pursuant to Section 313(a) of the Federal Power Act, 16 U.S.C. § 251(a) (2001), and Rules 212 and 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.713, the California Independent System Operator Corporation ("ISO") hereby submits this Motion for Clarification and Request for Rehearing, and Motion for a Stay of the Commission's May 2, 2002 Order ("May 2 Order") issued in the above-captioned dockets.[1] In support thereof, the ISO states as follows:

II. SUMMARY

The May 2 Order embodied the deliberations of the Commission on the matters litigated in the above captioned dockets. As such it contained Commission orders in respect of those matters requiring compliance from the ISO. After due deliberation on the text of the May 2

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1 *California Independent System Operator Corporation*, 103 FERC ¶ 61,114, (2003), Opinion No. 463.

Order, the ISO has sufficient doubt over the precise requirements of the May 2 Order that it is compelled to seek clarification on certain issues. Specifically, the ISO is requesting clarification that the May 2 Order summarily affirmed that changes to the ISO's rate structure, and specifically the change in the billing determinant for the Control Area Services ("CAS") charge for certain entities, which the Commission ordered, should be made on a prospective basis only. Further, where the Commission has reversed the terms of Judge McCartney's Initial Decision, *California Independent System Operator Corporation, et al.*, 99 FERC ¶ 63,020 (2002), ("Initial Decision"), in respect of the allocation of specified "charges for customers who primarily rely upon behind-the-meter load," 103 FERC at P 24, the ISO is unsure of the outcome required by the Commission or the means the ISO is expected to employ to achieve those ends. Separately, the ISO, for reasons of extreme practical difficulty, hardship and disruption, more fully outlined below, seeks rehearing from the Commission on aspects of the May 2 Order. Specifically, the ISO is seeking rehearing of the Commission's design of the new demand-based billing determinant element of the CAS charge. The ISO is also seeking rehearing of the Commission's summary affirmation of the Initial Decision with regard to direct billing of behind-the-meter load.

Lastly, given the breadth of the issues which this filing places before the Commission, and the practical difficulties in implementing certain aspects of the Commission's order, the ISO respectfully submits that it is reasonable and prudent for the Commission to stay the effectiveness of its May 2 Order, pending Commission action on the ISO's motion for clarification and request for rehearing. The ISO, therefore, moves for such a stay, as more fully supported below.

III. BACKGROUND

A. The California ISO

The ISO is a California non-profit public benefit corporation, organized pursuant to the Nonprofit Public Benefit Corporation Law for the charitable purposes set forth in Chapter 2.3, Part 1, Division 1 of the Public Utilities Code of the State of California. The ISO, created at the direction of the California Legislature, is charged with assuring open access to the electric transmission grid in the State of California and was organized specifically to ensure efficient use and reliable operation of that grid. *See* Cal. Pub. Util. Code § 300, *et seq.* (West Supp. 1998); CPUC Decision No. 95-12-063 (Dec. 20, 1995), *as modified by* Decision No. 96-01-009 (1996), 166 PUR4th 1 (1996). The ISO is a "public utility" as that term is defined in Section 201 of the Federal Power Act ("FPA"), 16 U.S.C. § 824(e) (2000). The ISO has no stockholders and no rate-base on which to earn a return. As a result, the ISO has only one source of revenues – its Grid Management Charge ("GMC"). *See* 99 FERC at 65,193; Tr. 218:13-14.

B. Procedural History

The ISO originally filed a GMC on October 17, 1997, as a bundled formula rate. The GMC was, and is, designed to collect the costs of operating the ISO. The filing of the original bundled GMC resulted in an uncontested settlement.[2] The process of unbundling the GMC in concert with a stakeholder committee began in early 1998. The instant case commenced with the filing of the unbundled GMC on November 1, 2000 in Docket No. ER01-313-000 ("2001 GMC"). The filing was noticed by the Commission on November 6, 2000. Multiple parties intervened in response to the ISO's filing.[3] On December 15, 2000 the ISO submitted updated

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2 *California Independent System Operator Corp.*, 83 FERC ¶ 61,247 (1998).

3 The parties intervening were: California Electricity Oversight Board ("EOB"), California Power Exchange Corporation ("CAL PX"), California Municipal Utilities Association, Calpine Corporation,

cost support data to the Commission. The ISO's December 15th filing was assigned to Docket No. ER01-313-001. On December 29, 2000, the Commission accepted the ISO's unbundled GMC filing, the December 15th filing, and a filing by PG&E to pass through the ISO's GMC charges, all to be effective January 1, 2001, consolidated the ISO's and PG&E's dockets and set them for hearing. *California Independent System Operator Corp.*, 93 FERC ¶ 61,337 (2000).

In the hearing on the ISO's 2001 GMC, intervening parties challenged – among other elements – the overall level of the ISO's revenue requirement; the three service category design of the GMC; certain cost allocations among the three service categories; the design of the billing determinant for the CAS charge, for which the ISO used a billing determinant of Control Area Gross Load ("CAGL") that included load located with on-site generation behind an interconnection meter; whether changes to the rate design should be made on a prospective basis only; the ISO's creation of "Other Appropriate Parties" as a type of entity that did not have to qualify as a Scheduling Coordinator ("SC") to receive bills directly; the use of utility distribution company ("UDC") SCs as the SC billing representative for behind-the-meter load; whether

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Calpine Power, City of Anaheim, City of Azusa, City of Banning, City of Colton, City of Redding, City of Riverside, City and County of San Francisco ("CCSF"), City of Santa Clara, City of Vernon, Cogeneration Association of California ("CAC"), Dynegy Power Marketing, Energy Producers and Users Coalition ("EPUC"), Independent Energy Producers Association, Metropolitan Water District of Southern California, Modesto Irrigation District ("MID"), M-S-R Public Power Agency, Northern California Power Agency ("NCPA"), Pacific Gas and Electric Company ("PG&E"), Public Utilities Commission of the State of California ("CPUC"), Sacramento Municipal Utility District ("SMUD"), San Diego Gas & Electric ("SDG&E"), San Francisco Bay Area Rapid Transit District ("BART"), Southern California Edison Company ("SCE"), Southern Energy California, LLC, Southern Energy Delta, LLC, Southern Energy Potrero, LLC, Transmission Agency of Northern California ("TANC"), Trinity Public Utility District, Turlock Irrigation District ("TID"), and Western Area Power Administration ("WAPA"), Western Power Trading Forum. The following parties moved to intervene out-of-time after the Initial Decision was issued: the California Cogeneration Council ("CCC"), Electricity Consumers Resource Council ("ELCON"), the United States Combined Heat and Power Association, the American Iron and Steel Institute, the American Forest & Paper Association, the American Petroleum Institute ("API"), the National Petrochemical & Refiners Association ("NPRA"), the Fertilizer Institute, and the Chemical Industry Council of California (collectively, "Industrial Associations"). The interventions made after the Initial Decision was issued were rejected by the Commission. 103 FERC at P 8.

certain costs were appropriately included in the ISO's 2001 revenue requirement; when the ISO should be required to file new GMC rate cases; and whether the ISO should undertake a reevaluation of the GMC's design.

A hearing was conducted in these proceedings from November 13, 2001 until December 21, 2001 and an Initial Decision was issued by the Presiding Administrative Law Judge on May 10, 2002.[4]

The Initial Decision found that the ISO's revenue requirement was just and reasonable, with the exception of approximately $1.8 million associated with an estimate of incentive compensation; that the three service category structure was just and reasonable, 99 FERC at 65,075-65,077; that the ISO's CAS billing determinant of CAGL was just and reasonable, including the subsidiary finding that load located with on-site generation behind an interconnection meter benefited from the ISO's provision of CAS and therefore caused costs and should share in paying those costs, *id.* at 65,111; that the ISO's cost allocations were just and reasonable, *id.* at 65,092-65,093; that changes to the GMC's rate design were not warranted but, if such changes were to be ordered by the Commission, that such changes should be made on a prospective basis only, *id.* at 65,091; that the "Other Appropriate Parties" designation should not be voluntary and that OAPs should be charged directly, *id.* at 65,141; and that certain Governmental Entities ("GEs") and Qualifying Facilities ("QFs") also should be charged directly, in lieu of their SCs, assuming the Commission found that there were no "statutory,

4 A detailed procedural history of the case up through the Initial Decision is included as part of the Initial Decision at pages 65,071- 65,073.

regulatory, or jurisdictional impediments", *id.* at 65,145. The Initial Decision also directed the ISO to undertake a re-evaluation of its unbundled GMC in 2003.[5] *Id.* at 65,155.

Briefs on Exceptions were filed in response to the Initial Decision and the Commission addressed certain exceptions in its May 2 Order. The Commission summarily affirmed many of the findings of the Initial Decision without further discussion. *See* 103 FERC at P 7. Among the findings of the Initial Decision that the Commission did not discuss, and therefore appeared summarily to affirm, were the findings that any changes to the ISO's rate design should be applied prospectively only, and that QFs and GEs should be billed directly for the unscheduled portion of load under the CAS service category.

The Commission did discuss and address certain issues. The Commission affirmed that the ISO's revenue requirement was just and reasonable, *id.* at P 9, with the exception of the $1.8 million associated with an estimate of incentive compensation, which the Commission directed to be refunded. *See id.* at P 11. The Commission agreed that OAPs should not be a voluntary designation and directed the ISO to make a compliance filing in order to bill OAPs directly. *See id.* at P 39.

The Commission also found that the concept of "benefit" is equivalent to causing costs to be incurred from a cost causation perspective, *id.* at P 26, and that the Initial Decision was correct in finding that behind-the-meter load benefits from the ISO's CAS functions and should pay the GMC. *See id.* at 23-34. The Commission also found the ISO's method of estimating gross load for certain entities to be reasonable. *See id.* at P 28 and 34. The Commission differed with the Initial Decision, however, as to the billing determinant on the basis of which the CAS charge should be assessed on certain types of behind-the-meter load. *Id.* The May 2 Order

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[5] That re-evaluation process began in August of 2002 and is currently ongoing.

directed that rather than a charge on load, the ISO should implement a demand charge for load that receives service from behind-the-meter generation that has a capacity factor of 50% or greater. *Id.*

IV. CONCISE STATEMENT OF ISSUES FOR CLARIFICATION AND SPECIFICATIONS OF ERROR

A. Issues for Clarification

The ISO is seeking clarification as to the following issues:

1. That the Commission intended to uphold the Initial Decision's determination that changes to the ISO's rate design should be made on a prospective basis only;
2. How the Commission intended the demand charge on behind-the-meter load to function, including how and how often the capacity factor is to be determined;
3. If direct billing of QFs is confirmed despite the ISO's request for rehearing on that issue, how the ISO should implement that direct billing;
4. If direct billing of GEs is confirmed despite the ISO's request for rehearing on that issue, how the ISO should implement that direct billing;
5. Exactly what the Commission means by "factual" and "legal" support in the compliance filing it has directed the ISO to undertake regarding OAPs.

B. Specification of Error

The ISO respectfully alleges error as to the following issues and is therefore seeking rehearing:

1. If retroactive application of changes to the ISO's rate design was intended, the Commission erred in deviating from its prior precedent on this issue and, more generally, in ordering retroactive application;

2. If retroactive application of changes to the ISO's rate design was intended, the Commission erred in failing to specify that the ISO has, or in failing to specifically grant, the necessary surcharge authority to recover additional sums from certain entities in order to ensure that the ISO recovers the Commission-approved portion of the ISO's revenue requirement allocated to CAS;

3. The Commission erred in directing that a demand charge be used to assess the CAS charge to "[c]ustomers with behind the meter generation who primarily rely on that generation to meet their energy need," if that generation has a 50% or greater capacity factor;

4. The Commission erred in ordering a refund of $1.8 million when that amount already has been returned to ISO rate payers through the operation of the ISO's operating reserve account;

5. The Commission erred in ordering the ISO to bill QFs and GEs directly, in lieu of their Scheduling Coordinators.

V. REQUESTS FOR CLARIFICATION AND REHEARING

A. Prospective Treatment

1. Clarification that Prospective Treatment Is Intended for the Change to the Billing Determinant for the CAS Charge on Behind-the-Meter Load

In the Initial Decision, the Presiding Judge found that if the Commission should order changes to the service categories, those changes would be changes to the GMC's rate design and should be made on a prospective basis only. 99 FERC at 65,091. While the Initial Decision focused on changes to the rate design that would result from a change to the service categories, the Presiding Judge included in her discussion the rate design change that would result from a further unbundling of the CAGL billing determinant for CAS. *Id.* Including altering the design of the CAGL billing determinant in this discussion was appropriate, as any such modification is a change to the GMC rate design. The demand charge ordered by the Commission, which is discussed below, not only functions as a change to the billing determinant for the CAS charge, but in effect divides the CAS service category into two parts. In support of her conclusion that changes to the ISO's rate design should be applied prospectively only, the Presiding Judge agreed with the testimony of Commission Trial Staff and the ISO, and cited Commission precedent for the proposition that changes to rate designs should generally be made on a prospective basis.[6] The Initial Decision stated:

> For reasons set forth *supra*, I do not recommend changes to the service categories at this time; however if the Commission should direct changes to the service categories, I concur with the position of Staff that the changes should be effective prospectively. S-6 at 34 (Pointer). This is supported by a combination of factors, including Commission precedent... .

99 FERC at 65,091.

The Commission's further unbundling of the CAS service category to create two different CAS sub-categories, *i.e.*, a CAS charge assessed on CAGL for some entities and a CAS charge assessed on a demand charge basis for certain behind-the-meter load, is clearly a change to the basic rate design of the GMC that, according to the position stated in the Initial Decision, should be effective prospectively only.

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6 *See* 99 FERC at 65,091, citing *Commonwealth Edison Co.*, 23 FERC ¶ 61,219 (1983) (Commission applied a new pricing scheme prospectively); In *Commonwealth Edison Company,* 25 FERC ¶61,323 (1983), the Commission stated: "The courts have held in a number of cases that the choice of remedy is a matter within the Commission's discretion. <u>Our general policy has been to deny refunds when ordering a change in rate design because retroactive implementation may result in under collections by the company and may be unfair to the customers who cannot alter their past demands in light of the new rate design</u>." *Citing, Connecticut Light and Power Company*, Opinion No. 114-A, 15 FERC ¶61,056 (1981), *aff'd sub nom. Second Taxing District of the City of Norwalk v. F.E.R.C.*, 683 F.2d 477 (D.C. Cir. 1982); *Commonwealth Edison Company*, Opinion No. 63, 8 FERC ¶61,277 (1979), *aff'd sub nom. Cities of Batavia v. F.E.R.C.*, 672 F.2d 64 (D.C. Cir. 1982), (emphasis added).

Among parties filing briefs on exceptions, only the Modesto Irrigation District excepted to the Initial Decision's finding that changes to the GMC's rate design should be prospective. The May 2 Order does not identify the issue of prospective treatment for changes in rate design in its list, in Paragraph Six, of exceptions that it would discuss. Nor is the issue addressed anywhere else in the order. In Paragraph 7, the Commission stated, "As to the remaining issues raised on exceptions, the Commission finds, having reviewed the record, the Initial Decision, and the parties' briefs, that they were properly resolved by the Initial Decision." 103 FERC at P 7. The May 2 Order goes on to conclude that "[a]ny issues not specifically referenced in this opinion are likewise affirmed." *Id.* It appears, therefore, that the Commission intended any change in rate design that it might order, including the change it did order to the billing determinant for behind-the-meter load, to be applied only prospectively.

This conclusion that the Commission intended only prospective treatment is reinforced by the absence of any Commission discussion addressing the issue of surcharge authority for the ISO. In its initial filing of the 2001 GMC, the ISO requested a specific grant of surcharge authority in the event GMC charges already collected were ordered refunded, as would be the case in the event of a retroactive reallocation of charges among customers due to a rate design change.[7] In its order setting the filing for hearing, the Commission stated that there was no need to address the issue of surcharge authority before there was any order requiring retroactive alteration of the rate, *i.e.*, the issue was not ripe. *California Independent System Operator Corp.*, 93 FERC ¶ 61,337 (2000).[8] The Commission did not address the ISO's request for surcharge

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7 November 1, 2000 ISO GMC rate filing, Transmittal Letter at p. 11.

8 In that order the Commission stated: "With respect to the ISO's request for surcharge authority, we will deny that request as premature. Until a determination is made in the consolidated hearing proceeding regarding the material issues raised by the Intervenors, it is premature to address whether the

authority in its May 2 Order, which it surely would have done if retroactive application of changes to the rate structure had been intended. It is therefore the ISO's understanding that any change to the ISO's rate design required by the Commission's order is to be made effective prospectively.

The only change to the ISO's rate design required by the order is the replacement of CAGL as the billing determinant for the CAS charge for certain behind-the-meter load. While it appears fairly clear, for the reasons stated above, that the Commission upheld the Initial Decision's finding that prospective treatment would be appropriate for changes in rate design, including such a change, the ISO requests that the Commission explicitly clarify that it has upheld the Initial Decision with respect to this issue and that any replacement of the billing determinant for the CAS charge on behind-the-meter load that might be required by the Commission's order is to be applied only prospectively.

The May 2 Order directed that, in the event of requests for rehearing in these dockets, that the refund of $1.8 million was to be made after the final disposition of such rehearing requests. The ISO respectfully suggests that, for the reasons stated above and elsewhere in this pleading, changes to the GMC rate design should be applied prospectively from that same date.

2. Alternative Request for Rehearing on the Issue of Prospective Treatment of the Change to the Billing Determinant for the CAS Charge on Behind-the-Meter Load

In the alternative, if the Commission intended that the change to the billing determinant for the CAS charge on behind-the-meter load be applied retrospectively, presumably to January 1, 2001, the ISO requests rehearing on that issue and asks that the Initial Decision be affirmed so

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Commission will, in fact, order such refunds to certain customers and thus cause the ISO to seek to recover additional amounts from other customers."

that this change to the rate design will be applied prospectively only. The ISO submits that prospective-only treatment is consistent with Commission precedent and is required in this instance for independent reasons.

The rate for the CAS service category was set based on the volume, in MWh, of exports and CAGL that the ISO estimated for a given year. In making the estimate of CAGL, the ISO has included unscheduled behind-the-meter loads because, as the Commission now has affirmed, those loads benefit from the ISO's provision of CAS. The total volume of exports and CAGL estimated for the year functions as the billing determinant for the CAS category: the CAS rate is set by dividing the costs allocated to that category by the total volume of CAGL and exports. Therefore, the ISO will not recover the entirety of its Commission-approved costs within the CAS category if the actual volumes used to derive that rate are reduced below the estimated volumes used to set the rate.

The direction in the May 2 Order that the ISO utilize a demand charge for billing the CAS charge to certain behind-the-meter load reduces the CAGL volumes the ISO originally utilized to derive its CAS rate; for this reason, as noted above, the ISO will not be able to recover all of its Commission-approved costs in the CAS category through charging the CAS rate, as originally designed, to the remaining exports and CAGL. The amounts recovered through the demand charge ordered by the Commission for certain behind-the-meter load will not be sufficient to cover the shortfall in recovery of CAS costs that is caused by no longer billing the originally-designed CAS rate to the volumes represented by that load. This conclusion is clear from the Commission's stated purpose of substituting the demand charge for the originally designed rate: reducing the charges assessed to those behind-the-meter entities. 103 FERC at P 28. If the Commission's decision were to be applied retroactively, the ISO would be saddled with a rate set too low to recover its CAS costs using the lower CAGL volumes in concert with the May 2 Order's demand charge. While the precise extent of the shortfall is unclear, retail and wholesale behind-the-meter load accounted for approximately $5.6 million in 2001 alone, and the ISO's best current estimate is that the shortfall could well be several million dollars.

Any significant shortfall in recovery of the total CAS costs would prove very harmful to the ISO's viability, as it is a revenue-neutral entity with no shareholders, no retained earnings, and a limited operating reserve. The ISO's revenue requirement was, except for one limited modification representing $1.8 million, found to be just and reasonable. Because retroactive application of a change in rate design would likely cause an under-recovery of costs, any application of changes to the GMC's rate design on a retroactive basis would be in conflict with the Commission's affirmation of the propriety of the ISO's costs.

As the ISO has testified, its billing and accounting system software was set up only to administer the GMC as designed. Exh. ISO-21 at 60: 7-8. The ISO further testified that, because the ISO's rates are based on certain billing determinants for a three-category structure, changes to the GMC "would require the GMC rates for 2001 to be completely overhauled, because it would lead to changes in the billing determinants and their respective determinant volumes." *Id.* at 60:10-13. Assuming the logistical concerns regarding the Commission's suggested split billing of the CAS category (partially based on CAGL and exports, partially based on demand), discussed below, were not an impediment, applying a change to the billing determinant for CAS retroactively would require the ISO to re-run its billing for all periods affected, making determinations as to who had overpaid under the original single billing determinant scheme and who had underpaid. As explained below, if this sort of retroactive reallocation is to be required, surcharge authority for the ISO to recover additional amounts from customers who had initially underpaid is critical. However, even surcharge authority would not ensure that the ISO's Commission-approved costs are recovered, as surcharges would likely be levied against entities that are in bankruptcy, or are no longer participating in the ISO markets. Further, even assuming that surcharge authority was in place and that bankrupt or absent entities did not create a concern, other logistical impediments to retroactive billing exist. The ISO must re-run the settlement and billing of several months of transactions under the Commission's orders in the Refund Proceeding, Docket Nos. EL00-95-000, *et al.*, a process that is likely to take several months to complete once underway. Further, even prior to that re-run of the market, the ISO must complete several preparatory re-runs to incorporate changes to the underlying data necessitated by settlement of disputes and other developments.[9] If the ISO is directed to apply rate design changes to the 2001 GMC, it most likely could not even begin the process until sometime in 2004. In addition, because the demand charge outlined by the Commission creates two sub-categories of the CAS charge (one billed on CAGL and exports, and one billed on a demand basis), the ISO's CAS costs would need to be allocated between the two sub-categories, an allocation that is likely to be contentious among the affected parties. Attempting to apply a change to the CAS service category retroactively, given all of these facts, would require exceedingly complicated calculations and could well result in revenue shortfalls affecting multiple years.[10]

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[9] *See generally*, The ISO's Amendment 51 filing, submitted on April 15, 2003 in Docket No. ER03-746-000, detailing the various re-runs that currently are planned for 2003; *see also, Request for Clarification and Rehearing of the ISO* filed on April 25, 2003 in Dockets EL00-95-045, *et al.*

[10] While the May 2 Order technically only deals with the 2001 rates assessed by the ISO, because of the terms of a settlement agreement entered into between the ISO and several intervening parties for 2002 and 2003, retroactive changes to the 2001 GMC may apply to 2002 and 2003 as well. The settlement was filed by the ISO on October 17, 2002 and approved by the Commission in a December 26, 2002 Letter Order issued in Docket No. ER02-250-000, *et al.* In 2002 and 2003, the ISO retained the same three service category structure and the same billing determinants for those service categories. A retroactive change to the CAS billing determinant would require a reallocation of the 2002/2003 GMC settlement

In addition, it is unclear that any single behind-the-meter entity or group of such entities has maintained accurate – *i.e.,* settlement quality – records to prove the 50% or greater capacity factor that is required to obtain the benefit of the demand-charge billing approach ordered by the Commission. If records were to be supplied by any significant number of such entities, the ISO's Compliance Department would be overwhelmed by the requirement of conducting even the most cursory due diligence to validate such records. Discrepancies and disputes as to standards of validation would only serve to cause further delay and expenditure of resources.

Also, as already alluded to, the ISO's settlement systems would require considerable adjustment and manual revision to give effect to re-billing of any significant amount of the 2001 GMC. These tasks would have to be carried out in the same time span as other Commission-ordered adjustments, reruns, and refund calculations, making the tasks exceedingly difficult to accomplish if not to all intents and purposes impossible. In any case, much of the cost of this effort would necessarily fall into current years, and the resulting shift of costs from those who might benefit from such retroactive adjustment onto those in the current ISO markets would be wholly out of step with the prevailing principles adopted by the Commission of cost causation and avoidance of cost-shifting.

To avoid issues of refunds, surcharges, and potential under-recovery of approved costs, the Commission has established the general rule that changes in rate design should be implemented on a prospective basis. *See, e.g., Commonwealth Edison Co.*, 23 FERC ¶ 61,219 (1983) (Commission applied a new pricing scheme prospectively). In a related case, *Commonwealth Edison Company,* 25 FERC ¶61,323 (1983), the Commission stated:

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agreement rates. This reallocation could result in the loss of the settlement over the 2002/2003 period and may result in the need for the ISO to make a new Section 205 filing to ensure that its revenue requirement in 2002 and 2003 is recovered. As explained below, any reallocation would necessitate that the ISO have surcharge authority in order to recover its revenue requirement.

> The courts have held in a number of cases that the choice of remedy is a matter within the Commission's discretion. Our general policy has been to deny refunds when ordering a change in rate design because retroactive implementation may result in under collections by the company and may be unfair to the customers who cannot alter their past demands in light of the new rate design.

Citing, Connecticut Light and Power Company, Opinion No. 114-A, 15 FERC ¶61,056 (1981), *aff'd sub nom. Second Taxing District of the City of Norwalk v. F.E.R.C.*, 683 F.2d 477 (D.C. Cir. 1982); *Commonwealth Edison Company*, Opinion No. 63, 8 FERC ¶61,277 (1979), *aff'd sub nom. Cities of Batavia v. F.E.R.C.*, 672 F.2d 64 (D.C. Cir. 1982), *emphasis added.* The Commission's policy that changes to the design of rates should be made prospectively recognizes that a utility would under-collect its actual costs if required to make refunds to parties without an ability to charge others more than they had paid under the original rate design. Commission Staff cited this general precedent in its testimony, Exh. S-6 at 34. The Initial Decision also cited to the Commission's precedent in ordering that if any changes were made to the ISO's rate design, they should be implemented on a prospective-only basis. 99 FERC at 65,091. The Commission's now well-established policy of prospective application of changes in rate design should apply in the instant case as well.

B. Surcharge Authority

If the Commission did not intend to affirm the Initial Decision regarding the prospective treatment of changes to the ISO's rate design and instead intended that the replacement of CAGL as the billing determinant for applying the CAS charge to some portion of behind-the-meter load should be made retroactively, and if the Commission refuses to grant rehearing on that issue, it is crucial that the Commission grant the ISO surcharge authority[11] so that it can recover from other

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[11] Surcharges would allow entities that underpaid under any retroactive reallocation to be re-billed the additional sums by which they underpaid. The Commission has granted surcharge authority in the past to public utilities when an ordered change in rate structure resulted in a class of customers having been allocated a share of costs that was too low, together with refunds to a class of customers that had been

Scheduling Coordinators the portion of its revenue requirement for the years 2001, 2002, and 2003 that it will no longer recover from behind-the-meter load.[12] As the Commission itself has noted, application of rate design changes retroactively can result in a utility failing to recover its revenue requirement. *See Second Taxing District of the City of Norwalk v. FERC*, 683 F.2d 477 at 490 (D.C. Cir. 1982); *Commonwealth Edison Co.*, 8 FERC ¶ 61,277 (1979). This would be the case if the ISO were required to implement the change in billing determinant for behind-the-meter load without also being able to levy a surcharge on other parties in order to recover the portion of the ISO's revenue requirement that it would no longer recover from behind-the-meter load. The ISO first requested surcharge authority in the event of a retroactive change to the rate on January 22, 1999 in a request for rehearing of a Commission order in Docket No. ER99-473-000, *et al.*, [13] accepting continuation of the bundled GMC subject to refund.[14] The ISO again requested such authority in its November 1, 2000 filing.[15] The ISO reiterated the necessity of surcharge authority in its subsequent testimony and briefs.[16] The element of surcharge authority in the event of a retroactive change to the GMC rate design has thus been a part of the ISO's filing from its inception, providing notice to all parties that surcharges may be imposed in the event of a retroactive application of any change to the rate design. Indeed, the Commission even

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allocated a share of costs that was too high. *See Occidental Chemical Corporation v. PJM Interconnection, LLC and Delmarva Power & Light Company*, 102 FERC ¶ 61,275 (2003) at P 13.

12 *See* fn. 10.

13 *California Independent System Operator Corporation*, 85 FERC ¶ 61,433 (1998).

14 *See* Request for Rehearing of the ISO in Docket No. ER99-473-000, et al., January 22, 1999 at 1; 6-7. The 2001 unbundled GMC filing grew out of those proceedings.

15 *See* November 1, 2000 Transmittal Letter at page 11.

16 *See, e.g.*, Exh. ISO-21 at 52:4-21; 57:4-7, 10-14; ISO Initial Brief at 14-15; ISO Reply Brief at 22; ISO Brief Opposing Exceptions at 36.

addressed the ISO's initial request for surcharge authority in this docket in its order setting the filing for hearing, noting that at the time, the request was not yet ripe.[17]

The Presiding Judge, citing the ISO's arguments, recognized that if changes were ordered retrospectively, surcharge authority would be necessary if the ISO was to be able to recover its Commission approved costs. 99 FERC at 65,051. The reason for this is clear and has been explained by the ISO throughout this proceeding: If the ISO is directed to recalculate all, or some, of the rates under the GMC due to a retroactive change in the rate design, absent surcharge authority, it would under-recover its Commission-approved costs by having to refund monies to some parties without being able to recover the difference from the parties who, under such a recalculation, had underpaid.

Refunds made as part of a reallocation that would result from the retroactive change to the GMC's rate design also create additional complications, in the absence of surcharge authority enabling the ISO to recover the amount of the refunds from those who had underpaid according to the reallocation. First, the ISO may not have sufficient funding to provide refunds. The ISO, because of the 2000/2001 energy crisis and the bankruptcy of PG&E and the California Power Exchange, lost its investment grade credit rating in January 2001, and has not had the rating restored as of this date. As a result, the ISO has no access to lines of credit or other borrowing facilities. Accordingly, any refunds would have to be paid solely from the ISO's operating reserve account. Even if the ISO somehow had sufficient funding to pay the refunds from the operating reserve (the depletion of which would threaten the ISO's on-going ability to operate in

[17] *California Independent System Operator Corp., et al.,* 93 FERC ¶ 61,337 (2000).

the event of any need for cash), the reserves would have to be replenished from 2004 ratepayers. As a result, 2004 ratepayers would subsidize 2001 (and potentially 2002 and 2003) ratepayers.[18]

If the Commission intended to overturn the Initial Decision with respect to prospective treatment for changes in the GMC rate design, and if it also refuses to grant rehearing on that issue, the ISO requests that it explicitly grant the ISO surcharge authority so that the ISO can recover its Commission-approved costs.

C. The Commission Should Clarify How it Prefers the CAS Rate Design to Be Implemented

1. <u>Difficulties with the Demand Charge</u>

The May 2 Order introduces, for the first time in the 2001 GMC proceeding, a demand charge to be assessed on "[c]ustomers with behind-the-meter generation who primarily rely on that generation to meet their energy needs." 103 FERC at P 28. The Commission has instructed the ISO to allocate CAS costs to such customers who also have "generators with a 50 percent or greater capacity factor" based on "their highest monthly demand placed on the ISO grid." *Id.*

It is unclear to the ISO how the Commission envisions the demand charge concept being applied to the ISO rate structure. The current CAS charge is an energy charge (measured in megawatt hours or "MWh") not a demand charge (measured in megawatts or "MW").

In addition, the ISO does not possess the data necessary to determine a) whether a customer with behind-the-meter generation "primarily" relies on that generation to meet its energy needs; or b) whether that customer has a 50% capacity factor.

Finally, the ISO is concerned that, absent mitigating factors or explicit competent authority to the contrary, applying a demand charge for CAS on only one group of Market Participants may be discriminatory.

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[18] *See* fn. 10.

2. Lack of Clear Guidance

The May 2 Order offers scant description of the demand charge concept, and the ISO is unclear how best to apply it to the GMC. For example, if one class of customers is to be allocated CAS costs based on a demand charge, and all others are to be assessed based on an energy charge, it would appear to be necessary to divide the CAS revenue requirement into two subcategories. No guidance as to how this should be done has been provided, and any selection of a method by the ISO is certain to be disputed by affected intervenors. Further, it is difficult to see how the total charges would add up to a complete recovery of the ISO's costs. Under the current approach, with the energy charge, each customer is assessed based on the same billing determinant – Control Area Gross Load or "CAGL," plus exports. As described in the ISO Tariff included with the November 1, 2000 GMC filing, the "rate for the Control Area Service Charge will be calculated by dividing the GMC costs allocated to this service charge by the total Control Area Gross Load and exports, in MWh." ISO Tariff (Exh. J-2) Appendix F, Schedule 1. All of the CAGL and exports of all the customers naturally added up to 100% of the total, and thus both the total costs to be recovered through the energy charge and each entity's appropriate assessment of these costs was clear.

Under the partial demand charge concept now being ordered by the Commission, some portion of the CAS revenue requirement would have to be assigned to this demand subcategory and recovered from these behind-the-meter customers. It will not be possible to determine in a meaningful, equitable manner what fraction of CAS costs should be attributable to the "energy-charge customers" as compared to the "demand-charge customers." An additional problem with implementing the demand charge is how the Commission intends the ISO to allocate CAS costs on the basis of customers' "highest monthly demand placed on the ISO's grid." 103 FERC at P

28. As described below, the ISO could design a demand charge based on non-coincident peak demand, but is unaware of examples of this methodology being used in the past, and, particularly in the interest of avoiding further protests and complaints to the Commission, the ISO currently believes it should only proceed with clear direction from the Commission that this is indeed what was meant by "highest monthly demand placed on the ISO's grid."

3. Lack of Necessary Data

The ISO does not possess, nor could it obtain readily, if at all, the data necessary to determine exactly which Market Participants with behind-the-meter generation have a 50 % or greater capacity factor. Indeed, the list of appropriate Market Participants to be assessed the demand charge could well vary from month to month. The majority of Market Participants to which this would be applicable are customers of investor-owned utilities ("IOUs"). The IOUs may have the meter data for their QFs or co-generators; however, the data that is supplied to the ISO is the aggregation of the entire IOU service area, including industrial, commercial, agricultural, and residential customers, and is not broken out by individual behind-the-meter load. To the extent that a QF or co-generator is not under a Standard Offer Agreement with an IOU, in accordance with the ISO Tariff, that entity is required to have the appropriate gross metering and telemetry requirements. If the ISO has this data, then it could bill those entities correctly. However, the Commission has yet to rule whether the ISO can enforce this requirement on QFs and co-generators.[19] Consequently, the ISO has been estimating this data on an aggregate basis but the ISO could not use this data to bill individual customers.

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[19] An issue litigated in ER98-997-000 was whether QFs must comply with the ISO's gross metering and telemetry requirements. The initial decision was issued on August 3, 2001. Because the Commission has not issued an order yet, and the initial decision found that QFs did not have to comply with gross metering and telemetry requirements, the ISO has given QFs and co-generators temporary exemptions from the requirements pending the Commission order. Thus even if the entity has the data, they will not supply the data to the ISO.

Also lacking is the data necessary to determine whether a given customer with behind-the-meter generation "primarily" relies on that generation to meet its energy needs. The ISO is not aware of what a behind-the-meter customer's precise energy needs might be; by their very nature, these entities operate outside of the knowledge of the ISO. The ISO is aware of when these entities take energy from or provide energy to the ISO Controlled Grid, but that is not sufficient to determine whether the customer relies on its own generation *primarily*. Moreover, this, too, is a question that might be answered differently from month to month for a given customer, exacerbating the ISO's difficulty in determining which customers are to be assessed the demand charge.

Finally, the most substantial problem with regard to the data needed by the ISO to calculate the demand charge is the difficulty of determining the demand attributable to each entity. The ISO has no access to individual meter data. The QFs as a class comprise a wide range of types of facilities. Not only does the ISO have no meters on all such QFs, the ISO is unaware whether all QFs have metering capabilities that would be of use to the ISO in collecting and verifying the required data. Further, the variety of types of QF facilities implies that many will require not one but several meters to give an effective account of their capacity utilization. Correcting that situation would require considerable cooperation from each QF.

Because of these data limitations, the ISO's efforts to comply with the Commission's order could well be frustrated at the very start.

The ISO got around the problem of the lack of data to apply its energy charge in the 2001 GMC with regard to the portion of CAGL represented by load served by on-site generation (such as that of QFs) by estimating this load. The estimates developed for that purpose, described in the testimony of James Price (Exh. No. ISO-12), were based on the CAS charge being assessed as an energy charge, not a demand charge. Thus, this estimation methodology is not adaptable to the Commission's demand charge scenario. The ISO is unaware of a means to use this available data to develop a demand charge consistent with the May 2 Order.

A second difficulty in assessing one group of Market Participants a demand charge is the difficulty of billing certain behind-the-meter entities directly. This is described more fully in Section E, below.

4. Discrimination

Assessing customers on different bases for their appropriate share of the CAS charge raises a question of discriminatory treatment. That only certain Market Participants with behind-the-meter generation – *i.e.*, those with a 50% capacity factor – would be assessed a demand charge exacerbates the problem of discrimination. The ISO is concerned that Market Participants will have strong negative reactions to such a two-tiered structure, and will consider that they are being treated unfairly. It has been the ISO's intention in unbundling the GMC to seek the fairest and most even-handed treatment of its various types of customers, and it is concerned that that goal will be undermined if the partial demand charge is implemented. The ISO anticipates that its customers will disagree with the ISO's determinations of which entities are to be billed based on demand, and that these disagreements will lead to substantial litigation before the Commission.

5. Lack of Record

Another major concern the ISO has with the concept of the demand charge found in the May 2 Order is that it appears to be without foundation in the record developed before the Presiding Judge. Specifically, the concept of a 50% capacity factor essentially appears for the first time in the May 2 Order.

This gives rise to a concern that intervenors and other affected entities might object to any application of any element of this concept, absent the most explicit and detailed direction from the Commission. Even with such direction, certain entities might seek judicial review based on the absence of record support for the concept. The ISO, therefore, respectfully requests that the Commission reconsider the concept of the demand charge and 50% capacity factor.

D. The Commission Should Grant Rehearing on the Issue of the Demand Charge, and Instead Apply One of the Following Options for Assessing the CAS Charge

Because of the difficulty in interpreting how to apply the requirements of the May 2 Order with regard to the demand charge for behind-the-meter load, the ISO's lack of sufficient information to assess such a demand charge, and the concern that assessing the CAS charge on an energy basis for certain Market Participants and on a demand basis for others would be discriminatory, the ISO requests that the Commission grant rehearing on the issue of the application of the demand charge to certain behind-the-meter customers, and instead adopt one of the three options described below.

1. Retaining the *Status Quo*

By far the simplest method of recovering the costs of providing the CAS until the ISO files its revised GMC methodology to be effective January 1, 2004, is the *status quo* – an energy charge based on CAGL and exports. The Commission largely approved this methodology in its order, apart from the single issue of behind-the-meter generators with a 50% capacity factor. This group is estimated to represent a very small portion of the ISO's total load. In light of the comparatively small impact of these customers, and the disproportionate amount of disruption caused to all Market Participants due to the effort that would be required of the ISO to determine and to bill them for their appropriate share of the CAS using the Commission's demand charge concept (if, indeed, it could even be done), the ISO believes that this *status quo* solution is the best possible for this interim period.

Moreover, as the Commission is aware (*see* 103 FERC at P 14 and footnote 16) the ISO currently is engaged in a substantial stakeholder process to redesign its GMC. This process, which was ordered by the Presiding Judge in her Initial Decision in this proceeding,[20] began on August 29, 2002. It has been a broadly scoped, lengthy and painstaking attempt to achieve the best possible GMC design, giving effect to the concerns of as many stakeholders as possible, including those with behind-the-meter generation.

The results of this redesign will be filed in the late fall of 2003, in order that the rate design that results from it may be placed into effect starting January 1, 2004. It is unlikely that the Commission will be able to rule on all Requests for Rehearing and Clarification of the May 2 Order much in advance of the time when the 2004 GMC will be filed. In light of the confusion and difficulty for the ISO in attempting to discern the Commission's intent with regard to the demand charge, and the need for resolution of this confusion and difficulty prior to applying the Commission's directives, the ISO submits that the best course of action would be to allow the current GMC rate structure to remain in effect until the new filing for 2004 has been made effective.

2. <u>A Demand Charge for the Entire CAS Charge</u>

A second possibility would be to convert the entire CAS Charge into a demand charge. In applying such a demand charge, the ISO would bill the UDCs for all demand in their areas attributable to behind-the-meter entities, and allow these charges to be passed on to behind-the-meter entities in their areas as the UDCs see fit. The ISO would calculate this demand charge on

[20] 99 FERC at 65,155.

a non-coincident peak basis, which the ISO believes best approximates the Commission's direction to calculate the charge based on the "highest monthly demand placed upon the ISO's grid." The ISO would apply the non-coincident peak methodology on a Scheduling Coordinator basis, not an individual customer basis. In this manner, the ISO would not be dealing with apples and oranges in determining the appropriate charge to be assessed on its customers. It would base its calculations on data available to it and would be applying the charge in a non-discriminatory manner.

3. Retain the Status Quo with a 50% Reduction in the Assessment for Behind-the-Meter Load

A third option would be to assess all customers the CAS Charge based on the current energy charge methodology, but to provide for a 50% discount to behind-the-meter load. In this scenario, the ISO would continue to bill the SCs for the behind-the-meter load, with the 50% discount factored in, rather than billing the behind-the-meter entities directly.[21]

This option has the considerable benefits of being simple to implement, and possibly being the closest to the spirit of the May 2 Order. As noted above, the Commission has found that the ISO's assessment of the CAS charge based on CAGL and exports is just and reasonable, apart from certain behind-the-meter entities. Moreover, the ISO could continue to use its current estimation methodology with regard to behind-the-meter load, and thus the significant difficulties surrounding the availability of data necessary to apply a demand charge would not be present.

E. Direct Billing of Qualifying Facilities and Governmental Entities

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[21] The difficulties the ISO would experience in billing the behind-the-meter entities directly are discussed below.

Intertwined with the design of the demand charge on behind-the-meter load is the issue of the entity that is to be billed for assessments of the GMC to that load. The Initial Decision found (under Section I.J) that the ISO should bill QFs and GEs directly for the CAS charge on their behind-the-meter load. These findings appear to have been affirmed without discussion by the May 2 Order. As discussed below, due to an almost impossible logistical situation made even more complex by the demand charge as proposed in the May 2 Order, the lack of needed data, and the lack of any evidence in the record that direct billing of QFs or GEs would be feasible or how that direct billing would be done, the ISO is requesting rehearing of this issue. To order direct billing when it appears infeasible for the ISO not only threatens the ISO's ability to recover its FERC approved costs, but also threatens the Commission's finding in the May 2 Order that behind-the-meter entities benefit from Control Area Services and should be assessed the GMC.

Currently, the ISO assesses the GMC to behind-the-meter load by estimating the behind-the-meter gross load using the methodology described by Dr. James Price in his testimony. Exh. ISO-12. The ISO then sends bills to the utility that acts as the Scheduling Coordinator for that behind-the-meter entity.[22] The utilities as SCs then pass the GMC costs through to their customers, including the QFs. This pass-through of costs, as regulated for retail entities by the California Public Utilities Commission and by the Commission in the case of wholesale customers, rather than a "gross injustice", 99 FERC at 65,141, is a basic element of the ISO's Commission-approved open access transmission tariff ("ISO Tariff") and related agreements allowing – in fact requiring – that a Scheduling Coordinator be designated to represent and be the billing point for all participants on the ISO system.

22 Those QFs that are no longer functioning under the umbrella of another SC, but interact with the ISO directly as an individual SC, receive bills directly from the ISO as do all SCs.

As the ISO has argued, QFs operating under the umbrella of an SC should be billed through their SCs that schedule standby service for their load. Although some parties have suggested that the responsibility to serve as an SC does not apply during any hour in which the retail customer is served entirely by behind-the-meter generation, Tr. 1846:7 – 1847:15, that limitation is neither contemplated by the ISO Tariff nor by the SC agreement. Indeed, much of the standby energy delivered by a UDC is not scheduled, Tr. 2182:5-24, but no UDC party has disclaimed responsibility for the CAS costs associated with unidentified, but delivered, standby energy. Rather, the responsibilities of a SC extend to paying charges in accordance with the ISO Tariff (Exh. J-2) § 2.2.6.1, ensuring compliance by each of the Market Participants that it represents with all applicable provisions of the ISO Protocols, *id.* at § 2.2.6.9, and abiding by and performing all the obligations imposed by the ISO Tariff on SCs in respect to all matters set forth therein, *id.* at Original Sheet No. 359. The ISO has further pointed out that, under the terms of the ISO Tariff, Loads receiving standby service from a UDC are SC metered entities. *See* ISO Tariff (Exh. J-2) at Appendix A. An SC is responsible for collecting revenue quality meter data from the SC metered entities that it represents. *See* ISO Tariff (Exh. J-2) Metering Protocol at§ 1.3.2. The Metering Protocol also prohibits the netting of generation and load. *Id.* at § 2.3.5. Because the billing determinant for CAS is ordinarily measured by metered demand, ISO Tariff (Exh. J-2) Settlement and Billing Protocol § 3.1, which must be gross demand, it follows that the SC will be billed for, and is responsible for, the entire load of an SC metered entity for which it is responsible, not just the net load. A UDC that serves as an SC for end-use customers cannot limit its responsibility just to those hours during which the customer actually purchases energy from the UDC SC. The ISO has argued that this is consistent with a UDC's responsibilities as a regulated utility to provide reliable service. The CAS charges are part of the costs that the UDC pays – and charges the QFs it serves – to obtain the reliability that it must provide.

Contrary to the Initial Decision's characterization of billing SCs on behalf of their customers as creating "middle men" and, in so doing, creating additional administrative fees and expenses, 99 FERC at 65,145, this arrangement, under which SCs act as billing representatives for their customers, is a foundational element of the ISO's structure as a centralized transmission provider and adds a great amount of efficiency and cost savings to the ISO's operations. Under this structure, the ISO only has to prepare bills for about 80 SCs. If required to implement the direct billing directed by the Initial Decision, the ISO would have to break out charges for and direct bill *several hundred* separate entities. The ISO's finance and billing department could not possibly administer this increased workload without substantial increases in staff or new computer systems to automate the billing. Similarly, the ISO has no anticipation that entities provided such bills would pay them willingly. The ISO has encountered significant billing and collection difficulties since 2001 from Scheduling Coordinators with contractual relationships with the ISO. These problems pale in comparison to those that would be introduced in trying to directly bill and collect from several hundred different entities that have no contractual relationship to the ISO.

The ISO is also seeking rehearing, with regard to billing GEs directly for their behind-the-meter load not otherwise scheduled. The ISO has argued that the GMC should be assessed to the entities that act as the SCs for those GEs. The ISO has explained that entities that schedule on the ISO Controlled Grid in accordance with Existing Contracts or interconnection agreements have not entered into an agreement with the ISO. For example, under Section 2.3 of its RPTO Agreement, PG&E has agreed to be the SC for certain GEs with which it has Existing Contracts.

See, e.g., Exh. SMD-17 at unnumbered 11. Those GEs (along with the Existing Contracts) are identified in Appendix A to the Responsible Participating Transmission Owner ("RPTO") Agreement and include all of the GEs that are parties to this proceeding. Exh. ISO-27 at 5:10-22, 7:1. While arguments have been made that an RPTO is only an SC to the extent that it actually schedules energy for a load with generation behind a meter, no such limitation appears in the RPTO agreement. Moreover, the ISO has argued that such a limitation would make little sense given that the Existing Contracts identified in RPTO agreements may require the GE and RPTO to perform various tasks that assist, or are necessary for, the Control Area operator's fulfillment of its reliability functions, and may also establish the cost responsibility for those tasks. *See, e.g.*, Exh. SMD-24 § 4.12.2. Because the ISO has assumed the functions of the Control Area operator, but not the assignment of the Existing Contracts, it must rely upon the former Control Area operator (*i.e.*, the Participating Transmission Owner that is the contracting party for the Existing Contract) to fulfill its responsibilities under the Existing Contracts and to ensure the GEs fulfill theirs. These responsibilities pertain to the entire load of the GE, not just to the portion scheduled. *See, e.g., id.*; Exh. MID-12 § 4.1. The ISO believes that the appropriate Commission-approved agreements are in place to allow the SCs for GEs to be the billing representatives for the GEs' entire portion of the GMC, including any portion assessed on behind-the-meter load.

Direct billing of QFs and GEs also raises logistical and efficiency concerns. If the ISO is to bill QFs and GEs directly for the portion of their behind-the-meter load not otherwise scheduled by a Scheduling Coordinator, the ISO is faced with three types of bills for those entities: 1) those directly to the SCs for the QFs' and GEs' load scheduled to be served through them; 2) bills to QFs and GEs based on CAGL for unscheduled load; and 3) bills based on a demand charge to QFs and GEs that meet the 50% capacity factor. The demands on software development, billing and settlement resources, and even the logistics of simply implementing such a scheme begin to appear staggering. An apparently impossible situation is made decidedly so by the addition of the logistical problems surrounding the implementation of the 50% capacity criteria directed by the Commission to function as the cut-off to determine which behind-the-meter load is billed on the basis of CAGL and which is billed on the demand charge, as discussed above. The ISO, therefore, requests rehearing on this issue and a determination that – consistent with its FERC-approved Tariff – the ISO be directed to continue to bill the SCs of the GEs that are not OAPs, and the SCs of the QFs.

Finally, if the Commission denies rehearing, and the ISO is directed to bill QFs and GEs directly, the ISO requests clarification as to how direct billing should be made effective, *e.g.*, through a compliance filing similar to that requested for OAP direct billing and/or through the filing of unexecuted service agreements with the Commission.

F. Refund

In the May 2 Order, the Commission affirmed the finding of the Initial Decision that the ISO over-budgeted approximately $1.8 million for incentive compensation. 103 FERC at P 9-11. The May 2 Order directs the ISO to refund that sum to its ratepayers. The ISO seeks rehearing of this determination because 1) the $1.8 million already has been returned; and 2) the non-profit structure of the ISO would result in an additional refund being funded by the very ratepayers receiving the refund.

As an initial matter, the ISO again notes that the ISO's *only* source of funding, in the absence of any ability to incur debt, is its ratepayers. 99 FERC at 65,193; Tr. 218:13-14. While the Commission has traditionally used the tool of refunds to ensure that over-collected funds were returned to ratepayers, it has used that tool with traditional utilities. The ISO is a non-traditional utility with no shareholders to whom to issue shares, no retained earnings, and no other means of raising revenue. *Id.* The ISO is not arguing that because of its non-traditional structure, it should not return the money to its rate payers, but rather that as a part of its structure, it has in place a mechanism that returns amounts incurred above its costs. Tr. 505:5-7, 507:12 – 508:3, 2686:2-11. That mechanism worked to return any excess collections due to an overstatement in the ISO's 2001 revenue requirement.[23] In this case, the ISO's revenue requirement was overstated by $1.8 million for costs that the ISO did not incur. The ISO's ratepayers received the benefit of this failure to incur the costs, through the calculation of the operating reserve credit for 2002, where the 2001 operations and maintenance ("O&M") costs did not include this overstatement, but were an estimate of *actual* 2001 O&M costs.[24] As a result, the ISO has already returned the unspent $1.8 million to its ratepayers. Even apart from this, it should be noted that actual collections in 2001 were significantly *below* the ISO's filed revenue requirement due to lower volumes, such that there was in fact no net over-collection.

If the ISO were to make the $1.8 million refund in addition to the revenue credits applied toward the 2002 GMC, it would elevate form over substance. The ISO would have to pay the $1.8 million out of its operating reserve, now to be funded by the 2004 ratepayers. The deficit in the operating reserve would need to be made up under the ISO Tariff in the next year's rates. Customers would therefore simply receive a refund and then either be billed in 2004 or lose $1.8 million of any credit against the GMC if such a credit materializes for 2004. For the reasons set

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23 The information regarding the amounts returned to rate payers was submitted to the Commission as part of the ISO's 2002 GMC filing in Dockets ER02-250-000, *et al.*, filed on November 2, 2002. Specifically, these numbers appear in the testimony of Phil Leiber, Exh. ISO-1 at page 36.

24 *See* Exh. No. ISO-9 at 8 of the ISO's November 1, 2002 filing in Docket Nos. ER02-250-000, *et al.*

forth here, and in the record, the ISO respectfully requests that the Commission grant rehearing on this issue and find that the ISO has already returned over-collected sums by reducing the amount of its 2002 GMC revenue requirement.

G. Other Appropriate Parties

In paragraph 39 of the May 2 Order, the Commission affirmed the Initial Decision's finding that the ISO should bill OAPs and that such billing should not be limited to OAPs that volunteer to be billed directly.[25] 103 FERC at P 39. The Commission further directed that the ISO make a compliance filing defining the term,[26] clarifying to whom it applies, and providing its factual and legal justifications. *Id.*

The ISO is seeking clarification that the "factual" justification sought in the ISO's compliance filing is an identification of the entities that benefit from the ISO's services as described in the May 2 Order. Further, the ISO seeks clarification that the "legal" justification requested in the ISO's compliance filing means identification or creation of an ISO Tariff provision memorializing the nature and scope of the obligation.

VI. REQUEST FOR A STAY PENDING AN ORDER ON REHEARING

The ISO's Request for Rehearing and its Motion for Clarification raise significant issues. To the extent that the directives in the Commission's May 2 Order remain in effect during the pendency of the Commission's consideration of those issues, the ISO will be placed in an

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[25] In the testimony of Michael Epstein, several entities were identified as possible OAPs. Exh. No. ISO-27 at 7. The list of OAP-type entities for the CAS charge now appears to be limited to MID and TID, other entities having entered into arrangements, e.g. by signing a metered sub-system agreements or becoming participating transmission owners.

[26] The ISO submitted a tariff definition of "Other Appropriate Parties" as part of its 2002 GMC filing. The term is now a part of the ISO Tariff at Appendix A, Master Definitions Supplement.

impossible position that will interfere with its ability to recover its on-going costs or, possibly, to retain the revenue needed to cover its past costs. Accordingly, the ISO moves the Commission to stay the May 2 Order until an order on the merits of all requests for rehearing and clarification is issued.

A. Standard for Stay

In evaluating requests for a stay, the Commission applies the standard set forth in Section 705 of Title 5, U.S.C., formerly the Administrative Procedure Act. Under Section 705, an agency will grant a stay where "justice so requires." In applying that standard, the Commission will evaluate whether (1) the moving party will suffer irreparable injury absent a stay; (2) issuance of a stay would substantially harm other parties; and (3) issuance of a stay is in the public interest. *City of Tacoma*, 85 FERC ¶ 61,130 (1998); *KansOk Partnership*, 73 FERC ¶ 61,293 (1995); *Commonwealth Gas Pipeline Corp.*, 29 FERC ¶ 61,054 (1984). All elements of this standard are satisfied in this instance.

B. A Stay Is Required to Avoid Irreparable Injury.

Elements of the Commission's May 2 Order may make it impossible for the ISO to recover its full operating costs through its GMC rate. Such under-recovery may jeopardize the ISO's on-going operations. As explained above, the ISO does not understand how the Commission's demand charge is to function. The ISO's best guess appears to result in a scheme that is not feasible and, in any case, the ISO's best guess may turn out to be wrong once the Commission issues an order on rehearing. If the ISO bills its GMC incorrectly, even from the period of May 2, 2003 forward, the possibility arises that it may have to refund some of the collected charges with no guarantee of the surcharge authority needed to collect sums from those Market Participants that under-paid. Further, in the absence of a stay, the ISO will expend resources in terms of both staff time and capital in order to attempt to implement a demand charge that may differ from what the Commission outlines in its order on rehearing.

Similar issues arise with regard to the issue of the potential double-refund of $1.8 million, and the party to be billed the GMC where behind-the-meter load is part of the total load calculation, both issues on which ISO is seeking rehearing. Finally, even issues put forward for clarification, such as the temporal scope of the Commission's order and the proper way for the ISO to invoke the Commission's authority to bill OAPs, counsel that the ISO should refrain from possibly erroneous steps until the intent of the Commission's order is made clear.

C. A Stay Will Not Harm Other Parties.

While the ISO will suffer severe and irreparable injury if a stay is denied, a stay will not harm other parties. In fact, a stay may preserve other parties from the possibility of needless multiple rounds of re-billing if any aspect of the May 2 Order were to be implemented incorrectly in light of an order on rehearing.

D. The Public Interest Supports the Issuance of a Stay.

Staying the May 2 Order is in the public interest as such a stay will ensure that the Commission's findings are not applied erroneously, and will spare the needless incurring of costs on the part of the ISO and other parties. A stay also will ensure that the ISO is clear as to how the May 2 Order is to be implemented, thus ensuring that the ISO recovers its revenue requirement, which is necessary if the ISO is to continue to meet its responsibility to maintain the reliability of the transmission grid.

A stay of the Commission's May 2 Order is therefore appropriate and the ISO requests that the Commission issue such a stay while the Commission considers the requests for rehearing and clarification that are submitted to it.

VII. CONCLUSION

WHEREFORE, the ISO respectfully requests rehearing and clarification on the issues discussed above, and further respectfully requests a stay of the Commission's May 2 Order until a final order is issued addressing all requests for rehearing and clarification on their merits.

Respectfully submitted,

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Dated: June 2, 2003

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 2nd day of June at Washington in the District of Columbia.

Theodore J. Paradise

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