SWIDLER BERLIN SHEREFF FRIEDMAN, LLP

THE WASHINGTON HARBOUR
3000 K STREET, NW, SUITE 300
WASHINGTON, DC 20007-5116
TELEPHONE (202) 424-7500
FACSIMILE (202) 424-7647
WWW.SWIDLAW.COM

RONALD E. MINSK
TELEPHONE: (202) 295-8385
FACSIMILE: (202) 424-7643
RMINSK@SWIDLAW.COM

NEW YORK OFFICE
THE CHRYSLER BUILDING
405 LEXINGTON AVENUE
NEW YORK, NY 10174
TELEPHONE (212) 973-0111
FACSIMILE (212) 891-9598

July 29, 2004

Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: California Independent System Operator Corporation,
Docket Nos. ER04-115-000 and EL04-47-000
&
Pacific Gas and Electric Company,
Docket Nos. ER04-242-000 and EL04-50-000

Dear Secretary Salas:

In accordance with the provisions of Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.602, the California Independent System Operator Corporation ("ISO") and Pacific Gas and Electric Company ("PG&E") submit an Offer of Partial Settlement in connection with the above-referenced proceeding.

I. CONTENTS OF SUBMISSION

Enclosed are the original and fourteen (14) copies of:

- a draft Commission Order;
- an Explanatory Statement; and,
- a Offer of Partial Settlement.

As indicated in the enclosed Explanatory Statement, this Offer of Partial Settlement is the product of negotiations that took place under the auspices of the Honorable Bruce Birchman, the Settlement Judge appointed by the Commission. The Offer of Partial Settlement resolves all issues that the Commission assigned for Settlement Discussions in its December 31, 2003 order, except for a single reserved issues described in Article V of the Offer of Partial Settlement.

No party taking part in those negotiations indicated opposition to the Offer of Partial Settlement.

In accordance with the provisions of Rule 602(c)(iii), the Parties submitting this Offer of Partial Settlement state that this filing contains copies of, or references to, all documents relevant to this Offer of Partial Settlement.

II. SERVICE OF SUBMISSION

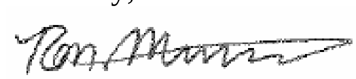
A copy of this submission is being served on all participants in the referenced proceeding and on all other persons required to be served by operation of Rule 602(d) of the Commission's Rules of Practice and Procedure.

III. NOTICE REGARDING FILING COMMENTS ON OFFER OF PARTIAL SETTLEMENT

In accordance with the provisions of Rule 602(d)(2), the ISO and PG&E hereby notify all participants in this proceeding as well as all other persons required by Rule 602(d)(1) that comments on the Offer of Partial Settlement are to be filed on or before August 19, 2004, and Reply Comments are to be filed on or before August 30, 2004 unless other dates are provided by the Commission. The ISO and PG&E request adherence to this comment period as provided in Rule 602(f)(2) in order to expedite the conclusion of this matter.

Two extra copies of this submission are provided to be date-stamped and returned to our messenger. Please contact the undersigned if you have any questions. Thank you for your assistance in this matter.

Sincerely,



Kenneth G. Jaffe
Ronald E. Minsk
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W.
Washington, D.C. 20007

Counsel for California Independent
System Operator, Inc.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

[Date]

In Reply refer to:
Docket Nos. ER04-115-000
EL04-47-000
ER04-242-000
EL04-50-000

Swidler Berlin Shereff Friedman, LLP
ATTN: Kenneth G. Jaffe
Counsel for California Independent System Operator Corporation
3000 K Street, N.W.
Washington, D.C. 20007-5116

Stephen Metague
Director, Electric Transmission Rates Department
Pacific Gas and Electric Company
77 Beale Street, Room 1339
San Francisco, CA 94105

Dear Mr. Jaffe and Mr. Metague:

On July 29, 2004, you filed in the above-referenced docket an Offer of Partial Settlement sponsored by the California Independent System Operation Corporation ("ISO") and Pacific Gas and Electric Company ("PG&E"). The Offer of Partial Settlement resolves all outstanding issues in the docket, except for one issue which was reserved for further consideration at the Commission.

On [date], the settlement judge certified the settlement to the Commission.

The subject settlement is in the public interest and is hereby approved. The revised wholesale charges specified in the settlement shall take effect as of January 1, 2004, and the ISO and PG&E shall revise rates and prepare refunds or surcharges as directed by the terms of the Offer of Settlement. The Commission's approval of this Offer of Partial Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding. The Commission retains the right to investigate the rates, terms and conditions under the just and reasonable and not unduly discriminatory or preferential standard of Section 206 of the Federal Power Act, 16 U.S.C. § 824e.

By direction of the Commission.

Magalie R. Salas,
Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010) and on all other persons required to be served by operation of Rule 602(d) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.602).

Dated this 29th day of July in the year 2004 at Folsom in the State of California.

/s/ Stephen A.S. Morrison
Stephen A.S. Morrison
(916) 608-7143

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
California Independent System	)	Docket No. ER04-115-000
Operator Corporation	)	Docket No. EL04-47-000
	)	
	)	
Pacific Gas and Electric Company	)	Docket No. ER04-242-000
	)	Docket No. EL04-50-000

EXPLANATORY STATEMENT

As required by Rule 602(c) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.602(c) (2003), (i) the California Independent System Operator Corporation ("ISO") and (ii) Pacific Gas and Electric Company ("PG&E") submit this Explanatory Statement to describe the basis for and significance of the parties' Offer of Partial Settlement ("Settlement Offer") in these proceedings. The Settlement Offer is reflected entirely in the Settlement Offer. This Explanatory Statement is not intended to alter any of the specific provisions of the Settlement Offer, and is provided solely for purposes of explanation in accordance with the Commission's Rules. All parties participating in the Settlement Conference have indicated in the course of settlement discussions that they either support or do not oppose the Settlement Offer.

I. BACKGROUND

On October 31, 2003, the ISO submitted to the Commission revisions to its Grid Management Charge ("GMC") ("October 31 GMC Submission"). The GMC is the rate through which the ISO recovers its administrative and operating costs, including the costs incurred in establishing the ISO prior to the commencement of operations. The ISO proposed to revise the GMC rate to unbundle charges further, increasing the number of service categories from three to seven and adjusting the charges for the existing categories, and designed the rate to collect an annual revenue requirement of $218.2 million, a decrease of $19.6 million from the revenue requirement collected by the 2003 GMC. Notwithstanding the overall reduction in the 2004 revenue requirement, because of the overall revision of the GMC rate design, charges to some Scheduling Coordinators were projected to increase while others were projected to decrease.

On November 28, 2003, PG&E submitted to the Commission revisions to its Pass-Through Tariff ("PTT") ("November 28 PTT Submission"). Pursuant to the PTT, PG&E recovers the GMC from entities for which PG&E acts as scheduling coordinator, specifically the City and County of San Francisco, the Modesto Irrigation District ("MID"), the Turlock Irrigation District, the San Francisco Bay Area Rapid Transit District and the Western Area Power Administration. Through its filing, PG&E sought to recover the GMC-related costs that the ISO proposes to allocate to PG&E with respect to scheduling coordinator service that PG&E provides to wholesale customers served under the existing Control Area Agreements. PG&E's filing also sought to align its PTT with the rate structure in the ISO GMC filing.

On December 31, 2003, the Commission accepted and suspended the ISO's revised GMC subject to refund, directed the appointment of a settlement judge, directed the ISO GMC Parties to seek to reach a settlement, and directed the initiation of an administrative hearing in the event that the ISO GMC Parties could not resolve their differences in settlement. On January 9, 2004, the Chief Administrative Law Judge issued an order designating the Honorable Bruce L. Birchman as the Settlement Judge in this docket.

On January 23, 2004, the Commission accepted and suspended PG&E's revised PTT subject to refund, and consolidated PG&E's November 28 PTT Submission with the ISO GMC filing.

The Parties have negotiated with the assistance of Judge Birchman. Those negotiations resulted in the proposed resolution of all issues that the Commission set for Settlement Discussions in its December 31, 2003 order, except for a single reserved issue described in Section II(E), below.

II. EXPLANATION OF THE TERMS OF SETTLEMENT

A. MODIFICATIONS TO ISO RATE DESIGN

The Settlement Offer accepts the revised GMC rate design, as reflected in the October 31 GMC Submission, with the following modifications:

1. The Settlement Offer caps the Core Reliability Services ("CRS") Charge at 65 percent of the costs allocated to the CRS Charge under the allocation factors included in the Current Rate. Costs not allocated to the CRS-Charge as a result of this limitation shall be allocated to the Energy Transmission Services - Net Energy ("ETS-NE") Charge of the GMC by increasing the costs allocated to the ETS-NE Charge under the allocation factors included in the Current Rate.
2. The Settlement Offer provides that the CRS-Charge will be collected from all loads in the ISO's Control Area and all exports scheduled by the ISO, as proposed in the October 31 GMC Submission, with the exception described in paragraph II(A)(5), below. However, the Settlement Offer divides the costs allocated to the CRS Charge by the ISO's cost-allocation process into two separate charges. First, the CRS-

Demand ("CRS-D") Charge, which will be billed on the basis of Scheduling Coordinators' Non-Coincident Peaks ("NCP"), provided that for any month in which a Scheduling Coordinator's metered NCP occurs during the off-peak hours, the CRS-D rate for that Scheduling Coordinator shall be equal to sixty-six (66) percent of the standard CRS-D rate. Second, loads associated with Energy Exports will pay a volumetric CRS-Energy Export ("CRS-EE") Charge, rather than the CRS-D Charge, which shall be assessed to megawatt-hours of load associated with Energy Exports.

3. The Settlement Offer reduced the Forward Scheduling ("FS") Charge by capping the FS Charge at 80 percent of the costs allocated to the FS Charge under the allocation factors included in the Current Rate. Costs not allocated to the FS Charge as a result of this limitation shall be allocated to the Congestion Management ("CM") Charge of the GMC by increasing the costs allocated to the CM Charge under the allocation factors included in the Current Rate.

4. The Settlement Offer reduces the FS Charge applicable to a Scheduling Coordinator's Inter-Scheduling Coordinator Energy and Ancillary Service Trade Schedules to one half of the standard FS Charge. The portion of the costs allocated to the FS service category associated with this discount shall be reallocated to the remaining GMC service categories in the same proportion as costs attributable to the Settlements, Metering, and Client Relations ("SMCR") Charge not recovered by the $500 per month SMCR Charge are allocated to the other GMC charges.

5. The Settlement Offer effectively reduces the GMC associated with transactions representing transfers from the Mohave generation facility to the loads of the Mohave co-owners located outside of the ISO Control Area by excluding 65 percent of those

Loads from the CRS-EE Charge and ETS-NE Charge, and effectively reduces the FS Charge assessed against Schedules submitted by PG&E solely in its role as Path 15 facilitator by excluding 65 percent of the number of such Schedules from the FS Charge.

6. The Settlement Offer reflects a resolution of the dispute regarding the GMC payable indirectly by MID through PG&E's PTT. For the duration of the Settlement Offer, pursuant to Section 3.8.1 of the Settlement Offer, MID shall pay the ISO directly $75,000.00 each month in settlement of MID's obligation under PG&E's PTT to pay a share of the GMC charges payable by PG&E with respect to Scheduling Coordinator ID "PGAB." If MID's annual energy load during a year exceeds its energy load during 2003 by more than 10 percent, or if MID's annual peak demand during a year exceeds its peak demand during 2003 by more than 10 percent, then MID shall pay the pro-rata increase in GMC attributable to such excess, in proportion to any such excess as follows: the percentage increase in MID's annual energy delivered to its retail customers or peak demand, as compared to 2003, whichever is greater, reduced by ten percent, multiplied by $900,000. On a quarterly basis, PG&E shall provide the ISO with MID's share of the GMC charges billed by the ISO to PGAB SCID during the quarter, and the ISO shall provide PG&E with a credit on the next available Settlement Statement for that amount. MID will pay the GMC charges assessed in accordance with this Settlement Offer and the ISO Tariff against MID's Loads, Schedules, and other activities under other SCIDs including, without limitation, MID's MID1 SCID, except that in the event that MID accepts responsibility for scheduling any load currently scheduled by PG&E under SCID

PGAB, the ISO will not charge any additional GMC at the tariffed GMC rate, but rather will attribute such schedules and load to the fixed $75,000.00 per month payment set forth above, provided that MID schedules such load under a new and separate SCID and the ISO shall not assess GMC charges to such SCID.

7. The Settlement Agreement also outlines the disposition of PG&E's charges under the PTT if the Commission's decision authorizing PG&E to pass-through to MID GMC charges assessed to PG&E under the PGAB SCID is reversed in a final order by a reviewing Court, not subject to further appeal, or if the Commission should rule on remand, in a final order, not subject to further appeal, that MID is not obligated to PG&E for any portion of the GMC payable by the PGAB SCID.

8. During the term of the Settlement Offer, MID agreed to provide the ISO, via ICCP link in a manner agreed upon by the parties, the certain data listed in Attachment F of the Settlement Offer, which the ISO represents will enhance the security and reliability of the grid. MID agreed to withdraw its alternate GMC rate design proposal in this proceeding and shall agree not to contest this Settlement Offer.

B. ISO BUDGET PROCESS

1. The Settlement Offer directs the ISO to engage an independent consultant to perform a Functional Assessment and Review ("FAR") of the ISO's management organization, which will cover issues such as, but not limited to, management structure, ISO functional organization and work processes. Prior to the consultant's submission of the final report to the ISO Board, the ISO GMC Parties will have the opportunity to meet with the consultant, receive an overview of the report and ask questions and make suggestions regarding the final report. Upon submission of the final report to the ISO Board, the final report will be provided on a

confidential basis to named attorneys representing the California Public Utilities Commission and the California Electricity Oversight Board and to the Commission's Settlement Judge in this docket (the "Reviewing Parties") for the purpose of reporting to the parties their opinions regarding whether the final report of the FAR satisfies the ISO's obligations to conduct such report. Upon approval by the ISO Board of any implementation plan prepared by the ISO in response to the final report of the FAR, the ISO shall provide any such implementation plan on a confidential basis to the Reviewing Parties for the purpose of reporting to the ISO GMC Parties their opinions regarding whether any such implementation plan satisfies the ISO's obligations under this provision.

2. In order to provide greater transparency in its Annual Budget process and to allow stakeholders greater access to ISO Budget data, the Settlement Offer directs the ISO to modify the process through which its Annual Budget is prepared. For the term of the Agreement, the ISO will name a senior member of the ISO finance staff to serve as liaison between stakeholders and the ISO and to coordinate the ISO's response to all reasonable stakeholder requests for information relating to the Annual Budget. The ISO also will host a meeting prior to the commencement of the annual budget process to receive ideas to control ISO costs, for projects to be considered in the capital budget development process, for reordering ISO priorities in the coming year, and to communicate the stakeholders' ideas to the ISO's Officers, Directors and Managers. The ISO then will provide stakeholders with: 1) proposed capital budgets with indicative projects for the subsequent calendar year; 2) a budget-to-actual review for capital expenditures for the previous calendar year; 3) a budget-to-actual review of current year capital costs; 4) expenditures and activities in detail for the next subsequent calendar year; 5) budget-to-actual review of expenditures and activities for the previous calendar year; and 6) a

budget-to-actual review of expenditures for the current year. Such information will be provided on a timely basis so that stakeholders may prepare timely comments on the materials to the ISO's Finance Committee.

3. Prior to the Board meeting scheduled to consider approval of the proposed budget, the ISO will hold a meeting open to all stakeholders to discuss the details of the ISO's budget and revenue requirement for the forthcoming year. The ISO will respond to all written comments on the draft budget submitted by stakeholders and/or issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

4. If the timetable for stakeholder participation in the budget development process precludes the ISO's putting revised GMC charges into effect by January 1 of the following year without waiver of the prior notice requirement in FERC's regulations, the ISO may represent to the Commission that the Parties support the waiver of that requirement so that revised GMC charges filed by no later than December 14 may become effective by January 1 of the following calendar year. Likewise, if the ISO requires a waiver to make revised GMC charges effective by January 1, PG&E may represent to the Commission that the Parties support a waiver of the prior notice requirement in FERC's regulations so that revisions to PG&E's PTT filed no later than December 31 may become effective by January 1 of the following calendar year.

5. The ISO will support and participate in a study coordinated by the North American ISOs/RTOs to assess the operations and costs of the North American ISOs and RTOs on a comparable basis and to develop benchmarks against which to measure the costs and performance of ISOs and RTOs. The ISO also will advocate for and actively promote efforts to make the results of such study available to the ISO GMC Parties.

C. Revenue Requirement

The Settlement Offer reduces the ISO's 2004 revenue requirement by $3 million, from $218.2 million to $215.2 million. If the ISO's Revenue Requirement does not exceed $218.4 million for Budget Year 2005 or $221.7 million for Budget Year 2006, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges in a manner consistent with the agreed upon rate design to collect such Revenue Requirement. If the ISO seeks to collect a Revenue Requirement for Budget Year 2005 that exceeds $218.4 million or Budget Year 2006 that exceeds $221.7 million, the ISO shall be required to make a Section 205 filing, limited in scope to adjusting the GMC charges (*i.e.*, with no modifications of the agreed upon rate design). The ISO will submit a filing under Section 205 for approval of the GMC charges to be effective as of January 1, 2007, which filing may or may not revise the rate design of the GMC.

If the ISO is not required to make a Section 205 filing to adjust the GMC charges for Budget Years 2005 and 2006 because the Revenue Requirement increases do not exceed the limits established in the preceding paragraph, then PG&E will not be required to make a Section 205 filing to pass through the ISO's adjusted GMC charges.

D. Reserved Issue

The Settlement Offer does not resolve the objection of San Diego Gas & Electic Company ("SDG&E") SDG&E to the application of the GMC charges to Energy Schedules of the Arizona Public Service Company and the Imperial Irrigation District on their respective shares of the Southwest Power Link, and does not prejudice the rights of SDG&E, the ISO, or any other Party to take any position with respect to that issue.

The ISO and the ISO GMC Parties support (or do not oppose) the resolution of all issues in the GMC Proceeding other than this reserved issue on the basis of this Settlement Offer and urge the Commission to accept this Settlement Offer as uncontested with respect to all issues in the GMC Proceeding other than this reserved issue.

E. PG&E PASS THROUGH TARIFF

Pursuant to the Settlement Offer and subject to the limitations therein, PG&E is entitled to collect, and the PTT customers are required to pay, all applicable GMC charges contained in the PG&E PTT. To the extent that PG&E's recovery of GMC charges from any PTT Customer is disallowed by Commission or Court order, PG&E will not attempt to recover that customer's GMC charges from the remaining PTT customers, i.e., the remaining PTT customers' GMC charges will not change solely as a result of PG&E's inability to collect a portion of the GMC charges from any one PTT customer.

PG&E will meet with PTT customers to explain the GMC allocation methodology and the derivation of GMC charges on a PTT Customer's GMC invoice, and will supply PTT customers with data necessary for the PTT Customers to validate their GMC invoices.

With respect to TID, PG&E will modify its 2004 PTT so that TID is allocated GMC components consistent with the Commission's Ruling, once the Commission has ruled on PG&E's Motion for Rehearing or Clarification in the 2001 ISO GMC and PG&E PTT dockets. Consistent with the Commission's decision, PG&E will refund to TID any overpayments, plus interest. While PG&E and TID await the Commission's decision and any court appeals, TID will pay all applicable GMC charges.

With respect to Western, if Western's appeal before the US Court of Appeals restricts or eliminates PG&E's ability to pass-through GMC charges, PG&E will assess only those GMC charges allowed by the Court's decision. PG&E will refund any GMC payments already made by Western that conflict with the Court's decision, subject to any rights to rehearing or appeal that PG&E may have.

PG&E and Western will work cooperatively to determine whether "double counting" of Western's GMC bill has occurred. During this time, PG&E and Western will work to recalculate Western's GMC charges by subtracting the portion of those charges currently in dispute, and Western will pay the undisputed GMC charges.

Nothing in this Section of the Settlement Offer relieves PG&E of its obligation to pay the GMC established pursuant to the Settlement Offer or binds the ISO or any non-PTT Customer.

F. TERM OF AGREEMENT AND MORATORIUM ON INTERIM FILINGS

Pursuant to the Settlement Offer, the ISO will not file under Section 205 of the Federal Power Act any modification of its rate design that proposes an effective date prior to January 1, 2007, except to the extent necessary to implement a revised market design based in whole or in part on a nodal system of Congestion Management employing locational marginal pricing. Further, no party that is bound by a Commission order in this proceeding accepting or approving this Settlement Offer shall file an application under Section 206 of the Federal Power Act to modify the rate design outlined in the Settlement that proposes a refund effective date for a modified GMC rate design that is earlier than January 1, 2007 or the effective date of modifications to the ISO Tariff to implement a revised market design based in whole or in part on a nodal system of Congestion Management employing locational marginal pricing, or to reduce the Revenue Requirement recovered through the GMC with an effective date before January 1, 2007 or the proposed effective date of an application submitted by the ISO under Section 205 of the Federal Power Act as permitted by the Settlement Offer.

III. INFORMATION TO BE PROVEDED WITH SETTLEMENT AGREEMENTS

Consistent with the requirements of a Notice to the Public dated October 23, 2004 from the Chief Administrative Law Judge regarding information that must be included in settlements filed with the Commission, the ISO and PG&E state that:

1) The issues underlying the agreement are explained above and in the text of the Offer of Partial Settlement;

2) None of the issues addressed in the Offer of Partial Settlement raise policy implications;

3) This Offer of Partial Settlement affects no other cases pending at the Commission;

4) The Offer of Partial Settlement does not involve issues of first impression and there are no previous reversals on the issues addressed in the agreement; and

5) The proceeding is subject to the just and reasonable standard.

IV. CONCLUSION

The ISO and PG&E believe that the Settlement Offer represents a fair and reasonable resolution of the issues in these proceedings. The Parties urge the Commission to rule on the Agreement expeditiously so that the rates provided for in the Settlement Offer may be placed into effect, and the other obligations imposed by the Settlement Offer may be undertaken.

Very truly yours,

Kenneth G. Jaffe
Ronald E. Minsk
Swidler Berlin Shereff Friedman, LLP
3000 K Street, NW Suite 300
Washington, DC 20007
Counsel for California Independent System Operator Corporation

Stephen Metague
Director, Electric Transmission Rates Department
Pacific Gas and Electric Company
77 Beale Street, Room 1339
San Francisco, CA 94105

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
California Independent System Operator Corporation	)	Docket No. ER04-115-000 Docket No. EL04-47-000
	)	
Pacific Gas and Electric Company	)	Docket No. ER04-242-000 Docket No. EL04-50-000

OFFER OF PARTIAL SETTLEMENT

This Offer of Partial Settlement ("Settlement Offer"), dated July 29, 2004, is submitted by (i) the California Independent System Operator Corporation ("ISO") with respect to Docket Nos. ER04-115-000 and EL04-47-000 (the "GMC Proceeding") and (ii) Pacific Gas and Electric Company ("PG&E") with respect to Docket Nos. ER04-242-000 and EL04-50-000 (the "PTT Proceeding"). This Settlement Offer sets forth a basis to fully and finally resolve all issues in the GMC Proceeding, with the exception of the reserved issue identified in Article V, below, and a basis to fully and finally resolve all issues in the PTT Proceeding. With respect to the GMC Proceeding, the ISO is authorized to state that the ISO GMC Parties support or do not oppose the resolution of the GMC Proceeding on the basis of this Settlement Offer.[1] With respect to the

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[1] The ISO GMC Parties are the Bonneville Power Administration, the California Department of Water Resources State Water Project, the California Electricity Oversight Board ("EOB"), the California Municipal Utilities Association, the California Public Utilities Commission ("CPUC"), the City of Redding, the City of Santa Clara, the Cogeneration Association of California, ConocoPhillips Company, the Energy Producers and Users Coalition, the Metropolitan Water District of Southern California, the Modesto Irrigation District ("MID"), Morgan Stanley Capital Group, Inc., the M-S-R Public Power Agency, PG&E, PacifiCorp, Powerex Corp., PPM Energy, Inc., San Diego Gas & Electric Corporation ("SDG&E") , San Francisco Bay Area Rapid Transit District ("BART"), Southern California Edison ("SCE"), TransAlta Energy Marketing (U.S.) Inc., and the Transmission Agency of Northern California.

PTT Proceeding, PG&E is authorized to state that the PG&E PTT Parties support or do not oppose the resolution of the PTT Proceeding on the basis of this Settlement Offer.[2] Agreement as to the terms of this Settlement Offer was reached in a settlement conference convened pursuant to a Federal Energy Regulatory Commission ("FERC" or "Commission") order dated December 31, 2003, *Order Accepting and Suspending Tariff Filing and Establishing a Hearing and Settlement Proceedings,* 105 FERC ¶ 61,406 (2003) (the "December 31 Order"), and a Commission order dated January 23, 2004, *Order Accepting for Filing and Suspending Revised Tariff, Instituting Section 206 Proceeding, Establishing Hearing Procedures and Consolidating Dockets,* 106 FERC ¶ 61,036 (2004) (the "January 23 Order").

ARTICLE I
BASIC UNDERSTANDINGS

1.1 On October 31, 2003, the ISO submitted to the Commission revisions to its Grid Management Charge ("GMC") ("October 31 GMC Submission"). The GMC is the rate through which the ISO recovers its administrative and operating costs, including the costs incurred in establishing the ISO prior to the commencement of operations. The ISO proposed to revise the GMC rate to unbundle charges further, increasing the number of service categories from three to seven and adjusting the charges for the existing categories, and designed the rate to collect an annual revenue requirement of $218.2 million, a decrease of $19.6 million from the revenue requirement collected by the 2003 GMC. Notwithstanding the overall reduction in the 2004 revenue requirement, because of the overall revision of the GMC rate design, charges to some

[2] The PG&E PTT Parties are the City and County of San Francisco ("CCSF"), MID, the Turlock Irrigation District ("TID"), BART and Western Area Power Administration ("Western"). The ISO, PG&E, the ISO GMC Parties and the PG&E PTT Parties are jointly referred to herein as the "Parties" and any one of them is referred to herein as a "Party."

Scheduling Coordinators are projected to increase while charges to others are projected to decrease.

1.2 On November 28, 2003, PG&E submitted to the Commission revisions to its Pass-Through Tariff ("PTT") ("November 28 PTT Submission"). Pursuant to the PTT, PG&E recovers the GMC from entities for which PG&E acts as Scheduling Coordinator, specifically CCSF, MID, TID, BART and Western. In the instant proceeding, PG&E seeks to recover the GMC-related costs that the ISO proposes to allocate to PG&E with respect to Scheduling Coordinator service that PG&E provides to wholesale customers served under the existing Control Area Agreements. PG&E's filing also sought to align its PTT with the rate structure in the ISO GMC filing.

1.3 The Commission's *December 31 Order* accepted and suspended the ISO's revised GMC subject to refund, directed the appointment of a settlement judge, directed the ISO GMC Parties to seek to reach a settlement, and directed the initiation of an administrative hearing in the event that the ISO GMC Parties could not resolve their differences in settlement.

1.4 The *December 31 Order,* and orders subsequently issued by the Chief Administrative Law Judge, granted motions to intervene filed by the Parties other than the ISO.

1.5 On January 9, 2004, the Chief Administrative Law Judge issued an order designating the Honorable Bruce L. Birchman as the Settlement Judge in this docket.

1.6 The Commission's *January 23 Order* accepted and suspended PG&E's revised PTT subject to refund, and consolidated PG&E's *November 28 PTT Submission* with the ISO GMC filing.

1.7 At settlement conferences convened by Judge Birchman on January 20, February 10, March 16, April 21 (telephone), May 5 (telephone), May 11, June 2, (telephone) and June

22, 2004 (telephone), the ISO GMC Parties reached agreement on a mutually acceptable basis for resolving all outstanding issues regarding the ISO's *October 31 GMC Submission*, with the exception of the reserved issue identified in Article V, below, and the PG&E PTT Parties reached agreement on a mutually acceptable basis for resolving all outstanding issues regarding PG&E's *November 28 PTT Submission*. The entire basis for the Parties' agreement is set forth in this Settlement Offer, including attachments hereto.

1.8 Capitalized terms used in this Settlement Offer shall have the meanings set out in the Master Definitions Supplement in Appendix A to the ISO Tariff unless otherwise stated in this Settlement Offer.

ARTICLE II
SCOPE OF SETTLEMENT

2.1 <u>Offer of Settlement</u>. The ISO and PG&E shall file this Settlement Offer with the Commission as an Offer of Partial Settlement under Rule 602 of the Commission's Rules of Practice and Procedure, 18 CFR § 385.602, as the full and final resolution <u>exclusively</u> of all issues in the above-captioned dockets, with the exception of the reserved issue identified in Article V, below. All of the ISO GMC Parties and PG&E PTT Parties support, or do not oppose, this Settlement Offer as an Offer of Partial Settlement.

2.2 <u>Replacement ISO Tariff Sheets</u>. Upon the Commission's acceptance of this Settlement Offer, the replacement sheets of the ISO Tariff contained in Attachment A to this Settlement Offer, which incorporate the modifications agreed upon in this Settlement Offer, shall take effect as of January 1, 2004, in lieu of the tariff sheets filed by the ISO as part of the *October 31 GMC Submission*, and accepted in the *December 31 Order*. In Settlement Statements issued to Scheduling Coordinators no later than ninety (90) days after the Effective Date of this Settlement Offer (as defined in Section 7.1, below), the ISO shall reflect adjustments for differences (both positive and negative) between the GMC charges paid by each Scheduling Coordinator for the period from January 1, 2004 through the effective date of such adjustments and the GMC charges reflected in Attachment A of this Settlement Offer and the applicable charge or credit for interest, calculated at the interest rate required by Section 35.19a of the Commission's regulations. The changes to the existing sheets of the ISO Tariff are marked on the replacement tariff sheets contained in Attachment B of this Settlement Offer. The settled GMC charges for 2004, resulting from the application of the rates set forth in the replacement tariff sheets contained in Attachment A to the ISO's 2004 revenue requirement, adjusted in accordance with Article IV, below, are set forth in Attachment C of this Settlement Offer. Upon the Commission's acceptance of the replacement tariff sheets contained in Attachment A, those tariff sheets shall be subject to further modification only as authorized or directed by the Commission in an order issued in connection with a future application under Section 205 or Section 206 of the Federal Power Act; however, the rights of the ISO GMC Parties to file such applications with the Commission shall be subject to the limitations set forth in Section 2.4 of this Agreement.

2.3 Replacement PG&E PTT Tariff Sheets. Upon the Commission's acceptance of this Settlement Offer, the replacement sheets of the PG&E PTT contained in Attachment D of this Settlement Offer, which incorporate the modifications agreed upon in this Settlement Offer, shall take effect, on January 1, 2004, in lieu of the tariff sheets filed by PG&E on November 28, 2003, and accepted in the *January 23 Order*. The changes to the existing sheets of the PG&E PTT are marked on the replacement tariff sheets contained in Attachment E of this Settlement Offer. Upon the Commission's acceptance of the replacement tariff sheets contained in Attachment D, those tariff sheets shall be subject to further modification only as authorized or directed by the Commission in an order issued in connection with a future application under Section 205 or Section 206 of the Federal Power Act. PG&E shall provide refunds, which include the interest provided by the ISO in Section 2.2 above, to reflect the terms of this Offer of Partial Settlement to the PTT Parties no later than ninety (90) days after the ISO makes adjustments to its Settlement Statements issued to Scheduling Coordinators set forth in Section 2.2 above, and shall include the applicable charge or credit for interest, calculated at the interest rate required by Section 35.19a of the Commission's regulations. The interest included as part of any refunds to a PTT Party shall be calculated based only on the amount which PG&E is refunding to the PTT Party, as calculated from the date that PG&E receives its adjustment to its Settlement Statement from the ISO, as set forth in Section 2.2 above.

2.4 Moratorium.

2.4.1. The ISO shall not file an application under Section 205 of the Federal Power Act to modify the rate design of the components of the GMC set forth in Article III of this Settlement Offer and in the replacement tariff sheets included in Attachment A that proposes an effective date for a modified GMC rate design that is earlier than the first to occur of: (a) January 1, 2007; or (b) the effective date of modifications to the ISO Tariff to implement a revised market design based in whole or in part on a nodal system of Congestion Management employing locational marginal pricing.

2.4.2. No party that is bound by a Commission order in this proceeding accepting or approving this Settlement Offer shall file an application under Section 206 of the Federal Power Act to: (a) modify the rate design of the components of the GMC set forth in Article III of this Settlement Offer and in the replacement tariff sheets included in Attachment A that proposes a refund effective date for a modified GMC rate design that is earlier than the first to occur of: (i) January 1, 2007; or (ii) the effective date of modifications to the ISO Tariff to implement a revised market design based in whole or in part on a nodal system of Congestion Management employing locational marginal pricing; or (b) to reduce the revenue requirement recovered through the GMC with an effective date before the first to occur of: (i) January 1, 2007; or (ii) the proposed effective date of an application submitted by the ISO under Section 205 of the Federal Power Act as permitted by section 2.4.3 of this Settlement Offer. No Party shall support such an application filed by any other person or urge the Commission to establish an investigation of the rate design of the components of the GMC or the revenue requirement collected by the GMC with a refund effective date prior to the date determined under the first sentence of this paragraph.

2.4.3. Nothing in this Section 2.4 or in this Settlement Offer shall be deemed or interpreted to restrict the rights of the ISO, of any other Party, or of any other party that is bound by a Commission order in this proceeding accepting or approving this Settlement Offer: (a) to apply to the Commission under Section 205 or Section 206, as applicable, to modify the rate design of the components of the GMC after the date determined under Section 2.4.1 or Section 2.4.2, as applicable; (b) to apply to the Commission under Section 205 to increase the revenue requirement recovered through the GMC with an effective date after December 31, 2004; (c) to protest an ISO filing at the Commission under Section 205 permitted under this Section 2.4, or submitted at the end of the moratorium described in this Section 2.4; (d) to apply to the Commission under Section 206 to reduce the revenue requirement recovered through the GMC with an effective date before the first to occur of (i) January 1, 2007; or (ii) the proposed effective date of an application submitted under Section 205 to increase such revenue requirement; or, (e) to apply to the Commission under Section 206 regarding the compliance of the ISO with the GMC, as set forth in the ISO Tariff, as modified by Attachment A hereof.

ARTICLE III
RATE DESIGN

3.1 Except as agreed to in this Settlement Offer, all components of the GMC rate set forth in the ISO's *October 31 GMC Submission* and accepted, subject to refund, by the *December 31 Order* (i.e., the "Current Rate") remain unchanged. It is agreed in settlement that the rate design of the Current Rate shall be modified in the respects set forth in the remaining sections of this Article III, in the manner implemented in the replacement tariff sheets contained in Attachment A.

3.2 The GMC costs allocated to the Core Reliability Services ("CRS") Charge of the GMC shall be capped at 65 percent of the costs allocated to the CRS Charge under the allocation factors included in the Current Rate. Costs not allocated to the CRS-Charge as a result of this limitation shall be allocated to the Energy Transmission Services - Net Energy ("ETS-NE") Charge of the GMC by increasing the costs allocated to the ETS-NE Charge under the allocation factors included in the Current Rate. The costs allocated to the CRS Charge shall be collected through two separate charges:

3.2.1 Loads associated with Energy Exports (as defined in Appendix A to the ISO Tariff, as modified by Attachment A of this Settlement Offer) shall pay the volumetric CRS-Energy Export ("CRS-EE") Charge, rather than the CRS Demand ("CRS – D") Charge, applied to a Scheduling Coordinator's non-coincident peak Demand for the month. The CRS-EE Charge shall be assessed to megawatt-hours of load associated with Energy Exports (in real-time and forward markets as applicable). Costs shall be allocated to the CRS-EE Charge in accordance with the allocation factors set forth in the GMC rate schedule included in Attachment A, which have been designed to recover the same revenues from Energy Export transactions as the CRS-D Charge was designed to recover from such transactions.

3.2.2 Loads not associated with Energy Exports shall pay the appropriate CRS-D Charge described in section 3.3 below, applied to a Scheduling Coordinator's non-coincident peak Demand for the month less the volume of Energy Exports included in the Scheduling Coordinator's non-coincident peak Demand for the month, if any. The Scheduling Coordinator's non-coincident peak Demand shall be the maximum value of its Metered Control Area Load during the month.

3.3 The CRS-D Charge will be billed on the basis of Scheduling Coordinators' Non-Coincident Peaks ("NCP"); *provided*, *however*, that for any month in which a Scheduling Coordinator's metered NCP occurs during the Off-Peak Period (defined as the period during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and Holidays), the CRS-D rate for that Scheduling Coordinator shall be equal to sixty-six (66) percent of the standard CRS-D rate. The denominator used to calculate the rate for the CRS-D charge shall be adjusted to reflect this discount.

3.4 The Forward Scheduling ("FS") Charge will be reduced by capping the FS Charge at 80 percent of the costs allocated to the FS Charge under the allocation factors included in the Current Rate. Costs not allocated to the FS Charge as a result of this limitation shall be allocated to the Congestion Management ("CM") Charge of the GMC by increasing the costs allocated to the CM Charge under the allocation factors included in the Current Rate.

3.5 The FS Charge applicable to a Scheduling Coordinator's Inter-Scheduling Coordinator Energy and Ancillary Service Trade Schedules shall be one half of the standard FS

Charge. The portion of the costs allocated to the FS service category associated with this discount shall be reallocated to the remaining GMC service categories in the same proportion as costs attributable to the Settlements, Metering, and Client Relations ("SMCR") Charge not recovered by the $500 per month SMCR Charge are allocated to the other GMC charges.

3.6 The GMC associated with transactions representing transfers from the Mohave generation facility to the loads of the Mohave co-owners located outside of the ISO Control Area, will be reduced by excluding 65 percent of those Loads from the CRS-EE Charge and ETS-NE Charge. Such excluded Load shall not be included in the denominators upon which the CRS-EE and ETS-NE rates are designed.

3.7 The FS Charge assessed against Schedules submitted by PG&E solely in its role as Path 15 facilitator will be reduced by excluding 65 percent of the number of such Schedules from the FS Charge. Such excluded Schedules shall not be included in the denominator upon which the FS Charge is designed. PG&E and the ISO shall establish a mechanism for the scheduling of load subject to the discount to facilitate the administration of this discount.

3.8 Modesto Irrigation District. Issues involving MID shall be resolved as follows:

3.8.1 Until the end of the moratorium under Section 2.4.1, MID shall pay the ISO directly $75,000.00 each month, subject to adjustment in Section 3.8.2, in settlement of MID's obligation under PG&E's PTT to pay a share of the GMC charges payable by PG&E with respect to Scheduling Coordinator ID "PGAB." The ISO shall not assess MID for any additional amount for GMC payable with respect to SCID PGAB. MID shall pay the GMC charges assessed in accordance with this Settlement Offer and the ISO Tariff against MID's Loads, Schedules, and other activities under other SCIDs including, without limitation, MID's MID1 SCID, except that in the event that MID accepts responsibility for scheduling any load currently scheduled by PG&E under SCID PGAB, the ISO will not charge any additional GMC at the tariffed GMC rate, but rather will attribute such schedules and load to the fixed $75,000.00 per month payment set forth above, provided that MID schedules such load under a new and separate SCID and the ISO shall not assess GMC charges to such SCID.

3.8.2 As soon as practicable after the end of each year, MID shall provide the ISO with the maximum NCP and total retail metered load for MID's system during the year. If MID's annual energy load for the year exceeded the energy load during 2003 by more than 10 percent, or if MID's annual peak demand during the year exceeded the peak demand during 2003 by more than 10 percent, then MID shall pay the pro-rata increase in GMC attributable to such excess, which shall be computed as follows: the percentage increase in MID's annual energy delivered to its retail customers or peak demand, as compared to 2003, whichever is greater, reduced by ten percent, multiplied by $900,000.

3.8.3 Within thirty (30) days of the issuance of Final Settlement Statements for each quarter of each year during the period that this Section 3.8.1 is in effect, PG&E shall provide the ISO and MID with a calculation of MID's share of the GMC charges billed by the ISO to PGAB SCID during such quarter, together with workpapers supporting such calculation. Subject to Sections 3.8.2 and 3.8.4, the ISO shall provide PG&E: with a credit on the next available Settlement Statement for that amount. Any difference, positive or negative, between the amount credited to PG&E and the amount paid by MID to the ISO under this provision for the year shall be reflected in the Operating and Capital Reserves Account, to be thereafter reflected in the GMC in accordance with Section 8.5 of the ISO Tariff.

3.8.4 MID has challenged the authority of PG&E charging MID for any portion of the GMC payable by the PGAB SCID in Docket Nos. ER01-424, et al. The Initial Decision and subsequent Commission Opinion Nos. 463 and 463-A in Docket Nos. ER01-313, et al. ruled that PG&E has the authority to pass-through to MID GMC charges assessed to PG&E under the PGAB SCID. Should the Initial Decision and the Commission's Opinion Nos. 463 and 463-A ruling be reversed in a final order by a reviewing Court not subject to further appeal, or if the Commission should rule on remand in a final order not subject to further appeal, such that MID is not obligated to PG&E for any portion of the GMC payable by the PGAB SCID, then the following shall occur:

(a) For all amounts credited to PG&E's SCID PGAB under Section 3.8.3, which were attributed to MID, PG&E shall pay or refund all such amounts to the ISO. MID, in turn, shall receive as credits to MID Settlement Statements, the equivalent of such amounts paid or refunded to the ISO by PG&E.

(b) If, for any calendar year, the amount PG&E is credited under Section 3.8.3 was less than $900,000, then:

(i) For the time period prior to the effective date of a final order of a reviewing Court or a final order by the Commission on remand, MID shall not receive a credit for the difference between the amounts credited to PG&E under Section 3.8.3 for that year and $900,000 plus any adjustment under Section 3.8.2.

(ii) For the time period after the effective date of a final order of a reviewing Court or a final order by the Commission on remand until the termination of this Settlement Agreement pursuant to Section 2.4.1, the following shall occur: MID shall not pay amounts that would have been attributed to it under PG&E's GMC Pass-Through Tariff under the PGAB SC ID. However, for any year, MID shall pay to the ISO the difference between the amounts that would have been attributed to it under PG&E's GMC Pass-Through Tariff under the PGAB SC ID, had PG&E's GMC Pass-Through Tariff still been in effect as to MID, and $900,000 plus any adjustment under Section 3.8.2.

3.8.5 During the period that Section 3.8.1 is in effect, MID shall provide the ISO, via ICCP link in a manner agreed upon by the parties, with the data listed in Attachment F of this Settlement Offer. By providing the data in Attachment F, MID shall not be considered to be taking service under the ISO Tariff, other than pursuant to MID's transactions under its Scheduling Coordinator Agreement with the ISO for SCID MID1. Such data shall be used for purposes directly related to maintaining the reliability of the ISO-Controlled Grid and for reliability studies, and shall not be used for rate studies or for the development of rates, charges and/or rate allocation methodologies.

3.8.6 Any disputes regarding the calculations required by this Section 3.8 shall be resolved in accordance with Section 13 of the ISO Tariff.

3.8.7 MID shall withdraw its alternate GMC rate design proposal in this proceeding and shall agree not to contest this Settlement Offer.

3.8.8 Upon the end of the moratorium under Section 2.4.1, this Settlement Offer is without prejudice to the ISO choosing to not include the provisions of this Section 3.8 in its subsequent GMC rate design proposal filed at the Commission, and this Settlement Offer is without prejudice to MID advocating before the Commission the GMC rate design proposal, as is or modified, that it included and advocated in its November 21, 2003, "Motion to Intervene, Motion to Reject, Protest and Request for Suspension and Hearing of the Modesto Irrigation District" in Docket No. ER04-115-000.

ARTICLE IV

REVENUE REQUIREMENTS REDUCTION AND DEVELOPMENT PROCESS

4.1 Functional Assessment Review. The ISO will engage an independent consultant to perform a Functional Assessment and Review ("FAR") of the ISO's management organization. The FAR will cover issues such as, but not limited to, management structure, ISO functional organization and work processes. The selected consultant will be from among independent firms with a national reputation in the areas to be covered by the FAR and the ISO will promptly apprise the ISO GMC Parties of the identity of the consultant selected. Prior to the consultant's submission of the final report to the ISO Board (which the ISO presently intends to be provided in time to be considered by the ISO Officers and the ISO Board as part of its 2005 Budget Process, though the ISO GMC Parties acknowledge that this schedule is subject to change), the ISO GMC Parties will have the opportunity to meet with the consultant, receive an overview of the report and ask questions and make suggestions regarding the final report. Upon submission of the final report of the FAR to the ISO Board, the final report will be provided on a confidential basis to named attorneys representing the California PUC and the California EOB and to the Commission's Settlement Judge in this docket (the "Reviewing Parties") for the purpose of reporting to the ISO GMC Parties, within forty-five (45) days of their receipt thereof, as to their opinions regarding whether the final report of the FAR satisfies the ISO's obligations under this provision. In addition, the Reviewing Parties may provide comments on the final FAR report to the ISO Board. Upon approval by the ISO Board of any implementation plan prepared by the ISO in response to the final report of the FAR, the ISO shall provide any such implementation plan on a confidential basis to the Reviewing Parties for the purpose of reporting to the ISO GMC Parties, within forty-five (45) days of their receipt thereof, as to their opinions regarding whether any such implementation plan satisfies the ISO's obligations under this provision. In addition, the Reviewing Parties may provide comments on any such implementation plan to the ISO Board.

4.2 Budget Process. In order to provide greater transparency in its Annual Budget process and to allow stakeholders greater access to ISO Budget data, so that stakeholders may gain an enhanced understanding of ISO spending priorities and greater confidence in ISO Budget decisions, the ISO will modify the process through which its Annual Budget is prepared in the following respects, beginning with the development of the ISO's 2005 budget:

4.2.1 The ISO will name a senior member of the ISO finance staff to serve as liaison between stakeholders and the ISO and to coordinate the ISO's response to all reasonable stakeholder requests for information relating to the Annual Budget. For purposes of this Section, a stakeholder's request for information deemed confidential by the ISO may still be regarded as reasonable, provided the requestor agrees to an appropriate non-disclosure agreement.

4.2.2 The ISO will convene, prior to the commencement of the Annual Budget process, an initial meeting with stakeholders to:

(a) Receive ideas to control ISO costs;

(b) Receive ideas for projects to be considered in the capital budget development process; and,

(c) Receive suggestions for reordering ISO priorities in the coming year.

Within 2 weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the ISO's Officers, Directors and Managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

4.2.3 Subsequent to the initial submission of the draft budget to the ISO Finance Committee, the ISO will provide stakeholders with the following information:

(a) Proposed capital budgets with indicative projects for the next subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and,

(b) Expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the ISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year.

The ISO shall provide such materials on a timely basis to provide stakeholders at least one full Committee meeting cycle to review and prepare comments on the draft Annual Budget to the ISO's Finance Committee.

4.2.4 At least one month prior to the Board meeting scheduled to consider approval of the proposed budget, the ISO will hold a meeting open to all stakeholders ("Stakeholder Budget Day") to discuss the details of the ISO's budget and revenue requirement for the forthcoming year. To the extent that such a meeting will deal with complex matters of budgetary and policy import, the ISO will endeavor to host a workshop on the ISO's budget preparation process in advance of the Stakeholder Budget Day to better prepare stakeholders.

4.2.5 Prior to a final recommendation by the ISO's Finance Committee on the ISO's draft Annual Budget, the ISO shall respond in writing to all written comments on the draft Annual Budget submitted by stakeholders and/or the ISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

4.2.6 The ISO will provide no fewer than forty-five (45) days for stakeholder review of its Annual Budget between initial Budget posting and final approval of the Budget by the Board. In the event that this would preclude the ISO's putting revised GMC charges into effect by January 1 of the following year without waiver of the prior notice requirement in FERC's regulations, the ISO is hereby authorized to represent to the FERC that the Parties support the waiver of that requirement so that revised GMC charges filed by no later than December 14 may become effective by January 1 of the following calendar year. The ISO agrees, however, that it will not ask for waiver of the 60-day prior notice requirement of the FERC's regulations for any GMC rate design filing proposed to take effect at the termination of the moratorium period established under Section 2.4.1 of this Settlement Offer. To the extent necessary to provide at least 60 days notice of such a GMC rate design change and to have GMC rates reflecting an approved ISO budget take effect on January 1, the ISO may submit a staged filing, two sequential filings or may amend a rate design filing to reflect a revenue requirement based on an ISO budget approved subsequent to the filing, and the Parties shall not oppose a filing or filings structured in any such manner on that basis. If the ISO requires a waiver to make revised GMC charges effective by January 1, PG&E is authorized to represent to the FERC that the Parties support a waiver of the prior notice requirement in FERC's regulations so that revisions to PG&E's PTT Tariff filed no later than December 31 may become effective by January 1 of the following calendar year.

4.3 Benchmarking. The ISO GMC Parties agree that benchmarking data, which would compare the relative costs of the California ISO with other North American ISOs and RTOs, would be useful to the ISO, the ISO GMC Parties and the FERC in order to foster greater transparency and understanding of ISO costs. Among other things, benchmarking is a tool that can ensure that the rates ultimately charged to consumers by the ISO are just and reasonable. Accordingly, the ISO will support and participate in a study coordinated by the North American ISOs/RTOs to assess the operations and costs of the North American ISOs and RTOs on a comparable basis and to develop benchmarks against which to measure the costs and performance of ISOs and RTOs ("North American Study").

4.3.1 The ISO will advocate for and actively promote efforts to make the results of the study available to the ISO GMC Parties, but the ISO GMC Parties acknowledge that the ISO has represented that the release of the study is dependent on the consent of the other participants. To the extent such data are releasable to third parties, the ISO will seek to provide the ISO GMC Parties access to confidential data pursuant to an appropriate non-disclosure agreement.

4.3.2 The ISO will cooperate and provide reasonable support to any other efforts sponsored by the EOB, the CPUC, or FERC to develop alternative studies.

4.3.3 Commencing within forty-five (45) days of the approval of this Settlement by the Commission, the ISO shall provide periodic written status reports to the ISO GMC Parties detailing the ISO's efforts to obtain the benchmarking information described above. Such reports shall be provided no less frequently than every ninety (90) days, until the North American Study is released.

4.4 Revenue Requirements. The ISO agrees to reduce its "as filed" 2004 Revenue Requirement by $3 million to $215.2 million.

4.4.1 If the ISO's Revenue Requirement for Budget Year 2005 does not exceed $218.4 million (101.5 percent of the 2004 Revenue Requirement) or its Revenue Requirement for Budget Year 2006 does not exceed $221.7 million (101.5 percent of $218.4 million), the ISO shall not be required to make a Section 205 filing to adjust the GMC charges in a manner consistent with the agreed upon rate design to collect such Revenue Requirement. In that event, following the approval of the budget by the ISO Board, the ISO shall post on its internet web site a table showing the GMC charges calculated by applying the ISO's Revenue Requirement based on the approved budget to the rates contained in Attachment A, together with workpapers showing the calculation of such charges.

4.4.2 In order for the ISO to collect a Revenue Requirement for either Budget Year 2005 that exceeds $218.4 million or Budget Year 2006 that exceeds $221.7 million, the ISO shall be required to make a Section 205 filing, limited in scope to adjusting the GMC charges (*i.e.*, with no modifications of the agreed-upon rate design), if it desires to collect the increased Revenue Requirement.

4.4.3 If the ISO makes no Section 205 filing to adjust the GMC charges for Budget Years 2005 and 2006 for Revenue Requirement increases that do not exceed the limits proscribed in Section 4.4.2 of this Settlement Offer, then PG&E will not be required to make a Section 205 filing to pass through the ISO's adjusted GMC charges. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective as of January 1, 2007. In such filing, the ISO may revise the rate design of the GMC, but shall not be required to do so.

ARTICLE V
RESERVED ISSUE

5.1 This Settlement Offer does not resolve the objection of SDG&E to the application of the GMC charges to Energy Schedules of the Arizona Public Service Company and the Imperial Irrigation District on their respective shares of the Southwest Power Link. The submission of this Offer of Partial Settlement shall not prejudice the rights of SDG&E, the ISO, or any other Party to take any position with respect to that issue. Without limiting the generality of the foregoing, nothing in this Settlement Offer shall prejudice: (a) the right of SDG&E to argue in this proceeding that the GMC charges should not be applied to such Schedules; or (b) the right of the ISO to argue in this proceeding that SDG&E's challenge to the applicability of GMC charges to such Schedules should be governed by the Commission's decisions with respect to such Schedules in Docket Nos. ER01-313-000, *et al.***,** and any further rulings on judicial review (and, if applicable, on remand) of the Commission's decisions. The ISO and the ISO GMC Parties support (or do not oppose) the resolution of all issues in the GMC Proceeding other than this reserved issue on the basis of this Settlement Offer and urge the Commission to accept this Settlement Offer as uncontested with respect to all issues in the GMC Proceeding other than this reserved issue.

ARTICLE VI
PG&E's PTT

6.1 Subject to the limitations set forth below in this Article VI, PG&E is entitled to collect and the PTT customers are required to pay all applicable GMC charges as set forth in the PG&E PTT in Attachment D. However, to the extent that PG&E is disallowed by Commission or Court order from recovering any portion of GMC charges from any PTT customer, PG&E shall not attempt to recover that customer's GMC charges from the remaining PTT customers, i.e., the remaining PTT customers' GMC charges will not change solely as a result of PG&E's inability to collect a portion of the GMC charges from any one PTT customer. PG&E will continue to meet with the PTT customers to explain both the GMC allocation methodology and the derivation of any particular charge on a customer's GMC invoice. PG&E will supply the PTT customers with the data necessary for the customers to validate their GMC invoices, as provided in the Consent to Disclose Customer Information and Confidentiality Agreement executed by the PG&E PTT Parties.

6.2 With respect to TID, once the Commission has ruled on PG&E's Motion for Rehearing or Clarification in the 2001 ISO GMC and PG&E PTT dockets (filed on February 23, 2004 in Docket Nos. ER01-313 and ER01-424), PG&E will modify its 2004 PTT so that TID is allocated GMC components consistent with the Commission's Ruling and PG&E shall refund to TID all overpayments, plus interest calculated at the interest rate required by Section 35.19a of the Commission's regulations, collected under the 2004 PTT. However, PG&E reserves the right to appeal this matter to the courts. If PG&E modifies its PTT to be consistent with any Commission ruling, PG&E reserves its right to further modify (or reverse prior modifications) its PTT consistent with any subsequent court ruling. While the parties await the Commission's decision and any court appeals, TID will pay all applicable GMC charges, as set forth in the PG&E PTT in Attachment D.

6.3 Issues Related to Western Area Power Administration.

6.3.1 If Western's pending appeal before the United States Court of Appeals for the District of Columbia Circuit restricts or eliminates PG&E's ability to pass-through GMC costs to Western, then PG&E will only assess GMC charges as allowed by the Court's decision, and PG&E will refund any GMC payments already made by Western that conflict with the Court's decision, subject to any rights to rehearing or appeal that PG&E may have. However, Western will pay all applicable GMC charges, subject to the limitations in Sections 6.3.2, 6.3.3 and 6.3.4 below, while the appeal is pending.

6.3.2 PG&E and Western will work cooperatively to determine whether "double counting" of Western's GMC bill actually occurs, and if so, what portions of Western's GMC billings represent duplicate charges. While this effort to resolve the "double counting" issue proceeds, PG&E and Western will work to recalculate Western's GMC charges by subtracting the portion of those charges currently in dispute. Once an agreed upon recalculation is developed, Western will pay the undisputed GMC charges. By making such payment, however, Western does not waive any legal rights or defenses it may have regarding PG&E's ability to impose GMC charges on Western, including, but not limited to, any rights and defenses raised by Western in its appeal before the United States Court of Appeals for the District of Columbia Circuit. However, nothing in this Settlement Offer shall restrict PG&E's right to enforce Section 6.4 (Customer Default) or any other section in PG&E's current or prior PTT.

6.3.3 PG&E and Western will work cooperatively to resolve other issues that may exist regarding PG&E's application of GMC charges to Western.

6.3.4 If PG&E and Western are not able to resolve any GMC-related issues, nothing in this Settlement Offer, including the language in Section 2.4, shall be deemed or interpreted to restrict the rights of PG&E or Western to apply to the Commission at a later date under Section 205 or Section 206, as applicable, for Commission resolution. Notwithstanding the language in Section 7.2, PG&E and Western agree, however, that PG&E shall carry the burden of proving that the increased rate or charge is just and reasonable.

6.4 Nothing in this Article VI shall (a) relieve PG&E of any obligation to pay the GMC established pursuant to Articles III and IV to the ISO; or (b) bind the ISO or any other ISO GMC Party that is not also a PG&E PTT Party.

ARTICLE VII
EFFECTIVE DATE AND OTHER CONDITIONS

7.1 This Settlement Offer shall become effective upon issuance by the Commission of a Final Order approving this Settlement Offer, including all Attachments, without modifications or condition or, if modified or conditioned, upon its acceptance by adversely affected parties as provided below. For purposes of this Settlement Offer a Commission order shall be deemed a Final Order when the last date for filing an application for rehearing has expired and no application is filed by that date. If any application for rehearing is filed, a Commission order shall be deemed a Final Order as of the date on which the right to seek rehearing expires, or if any request for rehearing is filed, as of the date on which rehearing is denied.

7.2 This Settlement Offer is made upon the express understanding that it constitutes a negotiated settlement and, except as otherwise expressly provided for herein, no settling Party shall be deemed to have approved, accepted, agreed to, or consented to any principle or policy relating to rate design, rate calculation, or any other matter affecting or relating to any of the rates, charges, classifications, terms, conditions, principles, issues or tariff sheets associated with this Settlement Offer. This Settlement Offer shall not be deemed to be a "settled practice" as that term was interpreted and applied in *Public Service Commission of the State of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980), and shall not be the basis for any decision with regard to the burden of proof in any future litigation. This Settlement Offer shall not be cited as precedent, nor shall it be deemed to bind any settling Party (except as otherwise expressly provided for herein) in any future proceeding, including, but not limited to, any FERC proceeding, except in any proceeding to enforce this Settlement Offer. This Settlement Offer, and any FERC order approving it, shall not be relied upon as evidence of the FERC's or any Party's support for any particular methodology or to constrain any Party's position at the end of the Effective Term.

7.3 This Settlement Offer is an integrated whole and its provisions are not severable. Notwithstanding the foregoing, if the Commission's approval of this Settlement is conditioned on the modification of this Settlement Offer or on any other condition, such modification or condition shall be considered to be accepted unless any Party objecting to such condition or modification files written notice of objection to the Settlement, as modified or conditioned, with the Commission, and serves such notice on the other parties within a period of ten days from the date of such Final Order.

7.4 The discussions among the Parties that have produced this Settlement Offer have been conducted on the explicit understanding, pursuant to Rule 602(e) of the Commission's Rules of Practice and Procedures, that all offers of settlement and any comments on these offers are privileged and not admissible as evidence against any participant who objects to their admission and that any discussion of the parties with respect to offers of settlement is not subject to discovery or admissible in evidence.

7.5 Headings in this Settlement Offer are included for convenience only and are not intended to have any significance in interpretation of this Settlement Offer.

7.6 Signatures may occur by counterparts. Such signatures shall have the same effect as if all signatures were on the same document.

Respectfully submitted,

Kenneth G. Jaffe
Ronald E. Minsk
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W.
Washington, D.C. 20007
(202) 424-7500

Counsel for California Independent System Operator, Inc.

Stephen Metague
Director, Electric Transmission Rates Department
Pacific Gas and Electric Company
77 Beale Street, Room 1339
San Francisco, CA 94105

Attachment A
Part 1

Revised ISO Tariff Sheets

8.2.4 Operating and Capital Reserves Cost.

The budgeted annual cost of pay-as-you-go capital expenditures and reasonable coverage of debt service obligations. Such reserves shall be utilized to minimize the impact of any variance between forecast and actual costs throughout the year ("Operating and Capital Reserves Costs").

8.3 Allocation of the Grid Management Charge Among Scheduling Coordinators.

The costs recovered through the Grid Management Charge shall be allocated to the eight service charges that comprise the Grid Management Charge. If the ISO's revenue requirement for any service charge changes from the most recent FERC-approved revenue requirement for that service charge, the costs recovered through that service charge shall be delineated in a filing to be made at FERC as set forth in Section 8.4. The eight service charges are as follows:

(1) Core Reliability Services - Demand Charge,

(2) Core Reliability Services – Energy Exports Charge

(3) Energy Transmission Services Net Energy Charge,

(4) Energy Transmission Services Uninstructed Deviations Charge,

(5) Forward Scheduling Charge,

(6) Congestion Management Charge,

(7) Market Usage Charge, and

(8) Settlements, Metering, and Client Relations Charge.

The eight charges shall be levied separately monthly in arrears on all Scheduling Coordinators based on the billing determinants specified below for each charge in accordance with formulae set out in Appendix F, Schedule 1, Part A of this Tariff, subject to the requirements set out in Appendix F, Schedule 1, Part F of this Tariff.

8.3.1 Core Reliability Services – Demand Charge.

The Core Reliability Services - Demand Charge for a Scheduling Coordinator's Load that is not associated with Energy Exports is calculated using the Scheduling Coordinator's metered non-coincident peak hourly Demand during the month (in megawatts) less the volume of Energy Exports included in the Scheduling Coordinator's non-coincident peak hourly Demand for the month, if any; provided that if the Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400 the rate shall be sixty-six (66) percent of the standard CRS rate. The standard rate for the Core Reliability Services – Demand Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total of the forecasted metered non-coincident peak hourly Demand for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peak hour during the month occurs between the hour ending 2300 and the hour ending 0600, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.2 Core Reliability Services – Energy Exports Charge,

The Core Reliability Services – Energy Exports Charge for the load associated with a Scheduling Coordinator's Energy Exports is calculated using the Scheduling Coordinator's metered volume of Energy Exports (in megawatt-hours); The rate for the Core Reliability Services – Energy Exports Charge is determined by dividing the GMC costs allocated to the Core Reliability Services service category, including a specified percentage of the costs for the

Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.3 Energy Transmission Services Net Energy Charge.

The Energy Transmission Services Net Energy Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's Metered Control Area Load (in megawatt-hours). The rate for the Energy Transmission Services Net Energy Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Metered Control Area Load, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.4 Energy Transmission Services Uninstructed Deviations Charge.

The Energy Transmission Services Uninstructed Deviations Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's net uninstructed deviations by Settlement Interval. The rate for the Energy Transmission Services Uninstructed Deviations Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted net uninstructed deviations by Settlement Interval according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.5 Forward Scheduling Charge.

The Forward Scheduling Charge for each Scheduling Coordinator is calculated using the sum of that Scheduling Coordinator's Final Hour-Ahead Schedules, including all awarded Ancillary Services bids, with a value other than 0.03 MW. The Forward Scheduling Charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinating Energy and Ancillary Service Trades for each Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge. The rate for the Forward Scheduling Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Final Hour-Ahead Schedules and awarded Ancillary Service bids submitted to the ISO, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.6 Congestion Management Charge.

The Congestion Management Charge for each Scheduling Coordinator is calculated as the product of the rate for the Congestion Management Charge and the absolute value of the net scheduled inter-zonal flow (excluding flows pursuant to Existing Contracts) per path for that Scheduling Coordinator. The rate for the Congestion Management Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.7 Market Usage Charge.

The Market Usage Charge for each Scheduling Coordinator is calculated using the absolute value of the Scheduling Coordinator's market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval). The rate for the Market Usage Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted number of market purchases and sales, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.8 Settlements, Metering, and Client Relations Charge.

The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at $500.00 per month, per Scheduling Coordinator ID with an invoice value other than $0.00 in the current trade month, as indicated in Appendix F, Schedule 1, Part A of this Tariff. Excess GMC costs related to the provision of these services that are not recovered through this charge are allocated to the other GMC service categories as specified above and in Appendix F, Schedule 1, Part E of this Tariff.

8.4 Calculation and Adjustment of the Grid Management Charge.

The eight charges set forth in Section 8.3 that comprise the Grid Management Charge shall be calculated through the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The formula set forth in Appendix F, Schedule 1, Part C of this Tariff sums the Operating Costs (less any available expense recoveries), Financing Costs, and Operating and Capital Reserves Costs associated with each of the eight ISO service charges to obtain a total revenue requirement. This revenue requirement is allocated among the eight charges of the GMC through the application of the factors specified in Appendix F, Schedule 1, Part E of this Tariff.

The revenue requirement for each service then shall be divided by the forecast annual or periodic billing determinant volume to obtain a rate for each service, which will be payable by Scheduling Coordinators as set forth in Section 8.3. The rates so established will be adjusted annually, through the operation of the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The ISO shall post on its website each year, before the adjusted rates go into effect, as described in Appendix F, Schedule 1, Part D of this Tariff, data showing the rates adjusted to reflect any change in the annual revenue requirement, variance between forecast and actual costs for the previous year or period, or any surplus revenues from the previous year or period (as defined in Section 8.5), or the inability to recover from a Scheduling Coordinator its share of the Grid Management Charge, or any under-achievement of a forecast of the billing determinant volumes used to establish the rates. The circumstances under which the ISO is permitted to put the adjusted rates into effect without submitting a filing to the FERC are described in Appendix F, Schedule 1, Part D of this Tariff. Appendix F, Schedule 1, Part B of this Tariff sets forth the conditions under which a quarterly adjustment to the Grid Management Charge will be made.

8.4.1 Credits and Debits of the Grid Management Charge.

In addition to the adjustments permitted under Section 11.6.3.3, the ISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any overpayment or underpayment of the Grid Management Charge that the ISO determines occurred due to error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

8.5 Operating and Capital Reserves Account.

Revenues collected to fund the ISO financial operating reserves shall be deposited in an Operating and Capital Reserves Account until such account reaches a level specified by the ISO Governing Board. The Operating and Capital Reserves Account shall be calculated separately for each GMC service category (Core Reliability Services – Demand, Core Reliability Services – Energy Export, Energy Transmission Services – Net Energy, Energy Transmission Services – Uninstructed Deviations, Forward Scheduling, Congestion Management, Market Usage, and Settlements, Metering and Client Relations). The allocation factors, reassignments and reallocations specified in Schedule 1, Parts E and F, will be accounted for in the development of the Operating and Capital Reserves Account for each component. If the Operating and Capital Reserves Account as calculated for such service category is fully funded, surplus funds will be considered an offset to the revenue requirement of the next fiscal year.

8.6 Transition Mechanism.

During the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, the Original Participating TOs collectively shall pay to the ISO each year an amount equal to, annually, for all New Participating TOs, the amount, if any, by which the New Participating TO's cost of Existing High Voltage Facilities associated with Gross Loads in the PTO Service Territory of the New Participating TO is increased by the implementation of the High Voltage Access Charge described in Schedule 3 to Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in that is separate from the switchyard to which the Generating Unit is connected will not be considered to be electrically connected at the same point); and

(b) Load that is isolated electrically from the ISO Control Area (*i.e.*, Load that is not synchronized with the ISO Control Area).

Converted Rights Those transmission service rights as defined in Section 2.4.4.2.1 of the ISO Tariff.

Core Reliability Services - Demand Charge A component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Demand Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Core Reliability Services – Energy Export Charge A component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Energy Exports Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

CPUC The California Public Utilities Commission, or its successor.

Energy Export	For purposes of calculating the Grid Management Charge, Energy included in an interchange Schedule submitted to the ISO, or dispatched by the ISO, to serve a Load located outside the ISO's Control Area, whether the Energy is produced by a Generator in the ISO Control Area or a resource located outside the ISO's Control Area.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.
Ex Post Price	The Hourly Ex Post Price or the BEEP Interval Ex Post Price.
Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.

Master File	A file containing information regarding Generating Units, Loads and other resources.
Meter Data	Energy usage data collected by a metering device or as may be otherwise derived by the use of Approved Load Profiles.
Meter Points	Locations on the ISO Controlled Grid at which the ISO requires the collection of Meter Data by a metering device.
Metered Control Area Load	For purposes of calculating and billing the Grid Management Charge, Metered Control Area Load is: (a) all metered Demand for Energy of Scheduling Coordinators for the supply of Loads in the ISO's Control Area, plus (b) all Energy for exports by Scheduling Coordinators from the ISO Control Area; less (c) Energy associated with the Load of a retail customer of a Scheduling Coordinator, UDC, or MSS that is served by a Generating Unit that: (i) is located on the same site as the customer's Load or provides service to the customer's Load through arrangements as authorized by Section 218 of the California Public Utilities Code; (ii) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (iii) the customer secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or the customer's Load can be curtailed concurrently with an outage of the Generating Unit.

Schedule 1

Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of eight separate service charges: (1) the Core Reliability Services – Demand Charge, (2) the Core Reliability Services – Energy Exports Charge; (3) Energy Transmission Services Net Energy Charge, (4) the Energy Transmission Services Uninstructed Deviations Charge, (5) the Forward Scheduling Charge, (6) the Congestion Management Charge, (7) the Market Usage Charge, and (8) the Settlements, Metering, and Client Relations Charge.

1. The rate in $/MW for the Core Reliability Services – Demand Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any, as may be modified in accordance with Part F of this Schedule 1), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peaks occurring during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and holidays; provided that if a Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, the rate shall be sixty-six (66) percent of the standard Core Reliability Services – Demand rate.

2. The rate in $/MWh for the Core Reliability Services – Energy Export Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered volume of Energy Exports in MWh, as may be modified in accordance with Part F of this Schedule 1, for all months during the year.

3. The rate in $/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Control Area Load.

4. The rate in $/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net uninstructed deviations (netted within a Settlement Interval summed over the calendar month) in MWh.

5. The rate in $ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Final Hour-Ahead Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service bids; provided that the Forward Scheduling charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades for each

Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge.

6. The rate in $/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted within a Settlement Interval summed over the calendar month) in MWh.

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $500.00 per month, per Scheduling Coordinator Identification Number ("SC ID") with an invoice value other than $0.00 in the current trade month.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the ISO's filing or posting on the ISO Home Page, as applicable, if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted in accordance with the following formula:

According to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the 5% or greater change from the estimated billing determinant provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 8 of the ISO Tariff, the Grid Management Charge includes the following costs, as projected in the ISO's budget for the year to which the Grid Management Charge applies:

- Operating costs (as defined in Section 8.2.2)
- Financing costs (as defined in Section 8.2.3), including Start-Up and Development costs and
- Operating and Capital Reserve costs (as defined in Section 8.2.4)

Such costs, for the ISO as a whole, are allocated to the eight service charges that comprise the Grid Management Charge: (1) Core Reliability Services - Demand Charge, (2) Core Reliability Services – Energy Export Charge, (3) Energy Transmission Services Net Energy Charge, (4) Energy Transmission Services Uninstructed Deviations Charge, (5) Forward Scheduling Charge, (6) Congestion Management Charge, (7) Market Usage Charge, and (8) Settlements, Metering, and Client Relations Charge, according to the factors listed in Part E of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the Operating and Capital Reserve Account, as defined under Section 8.5, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual Grid Management Charge components, if, on an annual basis, the change is 5% or more.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

- Operating Expenses + Debt Service + [(Coverage Requirement x Senior Lien Debt Service) and/or (Cash Funded Capital Expenditures)] - Interest Earnings - Other Revenues - Reserve Transfer

Where,

- **Operating Expenses** = O&M Expenses plus Taxes Other Than Income Taxes and Penalties

- **O&M Expenses** = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- **Taxes Other Than Income Taxes =** those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- **Penalties** = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- **Debt Service** = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- **Coverage Requirement** = 25% of the Senior Lien Debt Service.
- **Senior Lien Debt Service** = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- **Cash Funded Capital Expenditures** = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.
- **Interest Earnings** = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.
- **Other Revenues** = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC reliability coordinator reimbursements, and fines assessed and collected by the ISO.
- **Reserve Transfer** = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)
- **Reserve Requirement** = 15% of Annual Operating Expenses.

A separate revenue requirement shall be established for each component of the Grid Management Charge by developing the revenue requirement for the ISO as a whole and then assigning such costs to the seven service categories using the allocation factors provided in Appendix F, Schedule 1, Part E of this Tariff.

<u>Part D – Information Requirements</u>

Budget Schedule

The ISO will convene, prior to the commencement of the Annual Budget process, an initial meeting with stakeholders to: (a) receive ideas to control ISO costs; (b) receive ideas for projects to be considered in the capital budget development process; and, (c) receive suggestions for reordering ISO priorities in the coming year.

Within 2 weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the ISO's officers, directors and managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

Subsequent to the initial submission of the draft budget to the finance committee of the ISO Governing Board, the ISO will provide stakeholders with the following information: (a) proposed capital budget with indicative projects for the next subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the ISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. Certain of this detailed information which is deemed commercially sensitive will only be made available to parties that pay the ISO's GMC (or regulators) who execute a confidentiality agreement.

The ISO shall provide such materials on a timely basis to provide stakeholders at least one full committee meeting cycle to review and prepare comments on the draft annual budget to the finance committee of the ISO Governing Board.

At least one month prior to the ISO Governing Board meeting scheduled to consider approval of the proposed budget, the ISO will hold a meeting open to all stakeholders to discuss the details of the ISO’s budget and revenue requirement for the forthcoming year. To the extent that such a meeting will deal with complex matters of budgetary and policy import, the ISO will endeavor to host a workshop on the ISO’s budget preparation process in advance of the meeting to better prepare stakeholders.

Prior to a final recommendation by the finance committee of the ISO Governing Board on the ISO’s draft annual budget, the ISO shall respond in writing to all written comments on the draft annual budget submitted by stakeholders and/or the ISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders’ comments have been taken into consideration.

The ISO will provide no fewer than 45 days for stakeholder review of its annual budget between initial budget posting and final approval of the budget by the ISO Governing Board.

Budget Posting

After the approval of the annual budget by the ISO Governing Board, the ISO will post on its Internet site the ISO operating and capital budget to be effective during the subsequent fiscal year, and the billing determinant volumes used to develop the rate for each component of the Grid Management Charge, together with workpapers showing the calculation of such rates.

Annual Filing

If the Grid Management Charge revenue requirement for Budget Year 2005 does not exceed $218.4 million or its revenue requirement for Budget Year 2006 does not exceed $221.7 million, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to collect such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for Budget Year 2005 that exceeds $218.4 million or Budget Year 2006 that exceeds $221.7 million, the ISO must submit an application to the FERC under Section 205. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective as of January 1, 2007. In such filing, the ISO may revise the GMC rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

The ISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the ISO Governing Board. The periodic financial reports will be posted on the ISO's Website not less than quarterly.

Part E – Cost Allocation

1. The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the eight service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E. Expenses projected to be recorded in each cost center shall be allocated among the eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. In the event the ISO budgets for projected expenditures for cost centers are not specified in Table 1 to Schedule 1, such expenditures shall be allocated based on the allocation factors for the respective ISO division hosting that newly-created cost center. Such divisional allocation factors are specified in Table 1 to this Schedule 1.

Debt service expenditures for the ISO's year 2000 (or subsequently refinanced) bond offering shall be allocated among the eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. Capital expenditures shall be allocated among the eight charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E, for the system for which the capital expenditure is projected to be made.

Any costs allocated by the factors listed in Table 1 and Table 2 to the Settlements, Metering, and Client Relations category that would remain un-recovered after the assessment of the charge for that service specified in Section 8 of Part A of this Schedule 1 on forecasted billing determinant volumes shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

2. The allocation of costs in accordance with Section 1 and Tables 1 and 2 of this Part E shall be adjusted as follows:

Costs allocated to the Energy Transmission Services category in the following tables are further apportioned to the Energy Transmission Services Net Energy and Energy Transmission Services Uninstructed Deviations subcategories in 80% and 20% ratios, respectively.

Twenty (20) percent of the costs allocated to the Forward Scheduling Charge in the following Tables shall be reallocated to the Congestion Management Charge. A portion of the costs allocated to the Forward Scheduling Charge, associated with the fifty (50) percent reduction in the standard Forward Scheduling Charge to be applied to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades as specified in Part A of this Schedule 1, shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

Table 1

O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC #	Cost Center	CRS	ETS	FS	CM	MU	SMCR	Total
1100	**CEO Division**	**44.01%**	**21.51%**	**3.78%**	**4.61%**	**10.45%**	**15.63%**	**100%**
1111	CEO - General	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1241	MD02	6.95%	0%	13.86%	10.91%	28.38%	39.90%	100%
1521	Grid Planning	62.50%	37.50%	0%	0%	0%	0%	100%
1300	**Finance Division**	**44.04%**	**21.49%**	**3.62%**	**4.22%**	**10.31%**	**16.32%**	**100%**

1311	CFO - General	44.04%	21.49%	3.62%	4.22%	10.31%	16.32%	100%
1321	Accounting	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1331	Financial Planning and Treasury	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1351	Facilities	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1361	Security & Corporate Services	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

1400	**Information Services Division**	**38.25%**	**7.16%**	**9.74%**	**4.78%**	**9.23%**	**30.85%**	**100%**
1411	Chief Information Officer	38.25%	7.16%	9.74%	4.78%	9.23%	30.85%	100%
1422	Corporate & Enterprise Applications	33.28%	7.06%	1.16%	25.28%	12.58%	20.63%	100%
1424	Asset Management	35.30%	6.12%	10.91%	4.88%	10.50%	32.29%	100%
1431	End User Support	37.80%	14.44%	8.29%	3.5%	9.32%	26.65%	100%
1432	Computer Operations and Infrastructure Services	34.15%	9.21%	11.76%	3.08%	8.69%	33.11%	100%
1433	Network Services	43.38%	11.88%	9.39%	2.61%	9.23%	23.51%	100%
1441	Outsourced Contracts	42.25%	10.62%	10.25%	2.53%	9.07%	25.28%	100%
1442	Production Support	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1451	Information Support Services	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1461	Control Systems	96.44%	2.44%	0%	0%	0.56%	0.56%	100%
1462	Field Data Acquisition System (FDAS)	21.43%	0%	0%	0%	0%	78.57%	100%
1463	Operations Systems Services	50.44%	2.91%	6.01%	1.21%	5.95%	33.49%	100%
1466	Enterprise Applications	47.98%	7.30%	1.19%	1.34%	3.47%	38.72%	100%
1467	Settlement Systems Services	27.34%	11.20%	1.83%	2.05%	5.32%	52.25%	100%
1468	Corporate Application Support and Administration	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1469	Analytical and Reporting Applications	10%	0%	0%	65%	25%	0%	100%
1471	IT Planning	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1481	Markets and Scheduling System Services	46.85%	2.86%	23.68%	2.5%	17.64%	6.48%	100%
1482	Market Systems Support Services	44.94%	1.05%	18.51%	6.17%	23.78%	5.54%	100%
1500	**Grid Operations Division**	**66.71%**	**33.29%**	**0%**	**0%**	**0%**	**0%**	**100%**
1511	VP Grid Operations	66.71%	33.29%	0%	0%	0%	0%	100%
1542	Outage Coordination	95.11%	4.89%	0%	0%	0%	0%	100%
1543	Loads and Resources	48.95%	51.05%	0%	0%	0%	0%	100%
1544	Real-Time Scheduling	60%	40%	0%	0%	0%	0%	100%
1545	Grid Operations	67.47%	32.53%	0%	0%	0%	0%	100%
1546	Security Coordination	100%	0%	0%	0%	0%	0%	100%
1547	Engineering and Maintenance	46.42%	53.58%	0%	0%	0%	0%	100%

1548	OSAT Group - General	93.2%	6.80%	0%	0%	0%	0%	100%
1549	Operations Training	50.48%	49.52%	0%	0%	0%	0%	100%
1554	Special Projects Engineering	42.86%	57.14%	0%	0%	0%	0%	100%
1555	Operations Support Group	55.56%	44.44%	0%	0%	0%	0%	100%

1558	Transmission Maintenance	58.46%	41.54%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65.32%	34.68%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55.15%	44.85%	0%	0%	0%	0%	100%
1563	Operations Coordination	74.55%	25.45%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	76.92%	23.08%	0%	0%	0%	0%	100%
1566	Regional Coordination - General	100%	0%	0%	0%	0%	0%	100%
1600	**Legal and Regulatory Division**	**35.80%**	**21.78%**	**3.73%**	**7.18%**	**16.97%**	**14.54%**	**100%**
1611	VP General Counsel - General	35.80	21.78%	3.73%	7.18%	16.97%	14.54%	100%
1631	Legal and Regulatory	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1641	Market Analysis	15.32%	26.33%	0%	19.90 %	31.38%	7.07%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1661	Compliance - General	21.90%	20.37%	11.90 %	0%	28.50%	17.33%	100%
1662	Compliance - Audits	8.33%	0%	0%	0%	50%	41.67%	100%
1700	**Market Services Division**	**17.14%**	**2.43%**	**9.46%**	**9.39%**	**20.35%**	**41.23%**	**100%**
1711	VP Market Services - General	17.14%	2.43%	9.46%	9.39%	20.35%	41.23%	100%
1721	Billing and Settlements-General	25%	0%	0%	0%	0%	75%	100%
1722	Business Development Support	0%	0%	0%	0%	0%	100%	100%
1723	RMR Settlements	80.30%	19.70%	0%	0%	0%	0%	100%
1724	BBS - PSS	0%	0%	0%	0%	0%	100%	100%
1725	BBS - FSS	0%	0%	0%	0%	0%	100%	100%
1731	Contracts and Special Projects	43.17%	6.83%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	30.66%	0%	15.33 %	15.33 %	34.85%	3.83%	100%
1752	Manager of Markets	27.31%	5.46%	27.31 %	21.84 %	18.08%	0%	100%
1753	Market Engineering	21.32%	0%	0%	28.43 %	43.15%	7.11%	100%
1755	Business Solutions	5.91%	0%	47.27 %	11.82 %	29.10%	5.91%	100%

1756	Market Quality - General	0%	0%	0%	0%	70.93%	29.07%	100%
1757	Market Integration	7.38%	0%	29.52%	29.52%	26.20%	7.38%	100%

1800	**Corporate and Strategic Development Division**	**44.04%**	**21.49%**	**3.62%**	**4.21%**	**10.31%**	**16.33%**	**100%**
1811	VP Corporate and Strategic Development - General	44.04%	21.49%	3.62%	4.21%	10.31%	16.33%	100%
1821	Communications	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1831	Strategic Development	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1841	Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1851	Project Office	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1861	Regulatory Policy	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
Other Revenue and Credits								
	SC Application and Training Fees	0%	0%	0%	0%	0%	100%	100%
	WECC Reimbursement/NERC Reimbursement	100%	0%	0%	0%	0%	0%	100%
	Interest Earnings	36.64%	12.29%	9.34%	4.97%	11.47%	25.30%	100%
Debt Service Related Allocations		33.49%	7.93%	15.26%	5.19%	9.44%	28.69%	100%

Table 2

Capital Cost Allocation Factors

System	CRS	ETS	FS	CM	MU	SMCR	Total
ACC Upgrades (Communication between ISO & IOUs)	100%	0%	0%	0%	0%	0%	100%
Ancillary Services Management (ASM) Component of SA	15%	0%	40%	0%	45%	0%	100%
Application Development Tools	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Automated Dispatch System (ADS)	50%	0%	25%	0%	20%	5%	100%
Automated Load Forecast System (ALFS)	70%	0%	10%	0%	20%	0%	100%
Automatic Mitigation Procedure (AMP)	85%	0%	0%	0%	15%	0%	100%
Backup systems (Legato/Quantum)	23%	0%	22%	3%	7%	45%	100%

Balance of Business Systems (BBS)	0%	0%	0%	0%	0%	100%	100%
Balancing Energy Ex Post Price (BEEP) Component of SA	50%	0%	20%	10%	20%	0%	100%
Bill's Interchange Schedule (BITS)	85%	0%	0%	0%	15%	0%	100%
CaseWise (process modeling tool)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
CHASE	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Common Information Model (CIM)	100%	0%	0%	0%	0%	0%	100%
Compliance (Blaze)	19.17%	16.27%	9.5%	0%	32.83%	22.23%	100%
Congestion Management (CONG) (Component of SA)	10%	0%	0%	65%	25%	0%	100%
Congestion Reform-DSOW	50%	0%	0%	50%	0%	0%	100%
Congestion Revenue Rights (CRR)	0%	0%	0%	80%	20%	0%	100%
DataWarehouse	24.46%	18.27%	6.40%	8.74%	24.30%	17.82%	100%
Dept. of Market Analysis Tools (SAS/MARS)	15.32%	26.33%	0%	19.90%	31.38%	7.07%	100%
Dispute Tracking System (Remedy)	0%	0%	0%	0%	0%	100%	100%
Documentum	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Electronic Tagging (Etag)	100%	0%	0%	0%	0%	0%	100%
Energy Management System (EMS)	100%	0%	0%	0%	0%	0%	100%
Engineering Analysis Tools	60%	40%	0%	0%	0%	0%	100%
Evaluation of Market Separation	0%	0%	0%	50%	50%	0%	100%
Existing Transmission Contracts Calculator (ETCC)	25%	0%	20%	15%	20%	20%	100%
FERC Study Software	0%	0%	0%	0%	100%	0%	100%
Firm Transmission Right (FTR) and Secondary Registration System (SRS)	0%	0%	15%	60%	15%	10%	100%

Global Resource Reliability Management Application (GRRMA)	75%	15%	0%	0%	10%	0%	100%
Grid Operations Training Simulator (GOTS)	56%	44%	0%	0%	0%	0%	100%
Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,	0%	0%	100%	0%	0%	0%	100%
Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
IBM Contract	37.26%	14.44%	9.54%	3.52%	9.10%	26.13%	100%
Integrated Forward Market (IFM)	10%	0%	35%	0%	55%	0%	100%
Internal Development	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Interzonal Congestion Management reform - Real Time	50%	0%	0%	50%	0%	0%	100%
Land and Building Costs	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Local Area Network (LAN)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Locational Marginal Pricing (LMPM)	10%	0%	35%	0%	55%	0%	100%
Market Transaction System (MTS)	0%	0%	0%	0%	100%	0%	100%
Masterfile	20%	0%	20%	0%	55%	5%	100%
MD02 Capital	6.95%	0%	13.86%	10.91%	28.38%	39.90%	100%
Meter Data Acquisition System (MDAS)	0%	0%	0%	0%	0%	100%	100%
Miscellaneous (2004 related projects)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
Monitoring (Tivoli)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
New Resource Interconnection (NRI)	100%	0%	0%	0%	0%	0%	100%
New System Equipment (replacement of owned equipment)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
NT/web servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
NT-servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

Oracle Enterprise Manager (OEM)	27%	0.%	18%	5%	9%	41%	100%
Office Automation - desktop/laptop (OA)	44%	27%	4%	4%	10%	17%	100%
Office equipment (scanner, printer, copier, fax, Communication Equipment)	44%	21%	4%	4%	10%	17%	100%
Open Access Same Time Information System (OASIS)	10%	0%	25%	10%	35%	20%	100%
Operational Meter Analysis and Reporting (OMAR)	0%	0%	0%	0%	0%	100%	100%
Oracle Corporate Financials	44%	21%	4%	4%	10%	17%	100%
Oracle Licenses	27%	0%	18%	5%	9%	41%	100%
Oracle Market Financials BBS	0%	0%	0%	0%	0%	100%	100%
Out of Sequence Market Operation Settlements Information System (OOS)	5%	5%	0%	0%	90%	0%	100%
Outage Scheduler (OS)	50%	0%	10%	20%	20%	0%	100%
Participating Intermittent Resource Project (PIRP)	0%	0%	93.92%	0%	6.08%	0%	100%
Physical Facilities Software Application/Furniture/Leasehold Improvements	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Process Information System (PI)	80%	0%	0%	0%	10%	10%	100%
Rational Buyer	100%	0%	0%	0%	0%	0%	100%
Real Time Energy Dispatch System (REDS)	100%	0%	0%	0%	0%	0%	100%
Real Time Nodal Market	35%	0%	10%	0%	55%	0%	100%
Reliability Management System (RMS)	100%	0%	0%	0%	0%	0%	100%
Remedy (related to Transmission Registry, New Resource Interconnection, and Resource Registry)	100%	0%	0%	0%	0%	0%	100%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	100%	0%	0%	0%	0%	0%	100%
Resource Register (RR)	100%	0%	0%	0%	0%	0%	100%

RMR Application Validation Engine (RAVE)	100%	0%	0%	0%	0%	0%	100%
Scheduling & Logging for ISO California (SLIC)	65%	0%	15%	5%	15%	0%	100%
Scheduling Architecture (SA)	23.96%	0%	19.84%	25.87%	30.33%	0%	100%
Scheduling Infrastructure (SI)	0%	0%	93.92%	0%	6.08%	0%	100%
Scheduling Infrastructure Business Rules (SIBR)	0%	0%	93.92%	0%	6.08%	0%	100%
Security Constrained Economic Dispatch (SCED)	40%	0%	0%	0%	60%	0%	100%
Security- External/Physical	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Security-ISS (CUDA)	23%	0%	22%	3%	7%	45%	100%
Settlements and Market Clearing	0%	0%	0%	0%	0%	100%	100%
Sign Board (Symon Board maint.)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Startup Costs through 3/31/98, Working Capital-3 months	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Storage (EMC symmetrix)	18.67%	9.55%	13.71%	4.21%	11.77%	42.09%	100%
System Equipment Buyouts (lease buyouts)	43.27%	1.02%	7.34%	1.79%	11.03%	35.56%	100%
Telephone/PBX	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Training Systems	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation	100%	0%	0%	0%	0%	0%	100%
Transmission Map Plotting & Display	50%	50%	0%	0%	0%	0%	100%
Trustee Costs, Interest-Capitalized, User Groups	53.60%	0.55%	10.62%	15.74%	17.48%	2%	100%
Utilities - System i.e. Print drivers	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Vitria (Middleware)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Wide Area Network (WAN)	40.80%	2.14%	18.68%	1.31%	7.60%	29.48%	100%

Capital Expenditures for Systems not Specified	32.20%	7.40%	15%	5.50%	10.60%	29.30%	100%

Table 3

Reallocation Factors for Projected Unrecovered Portion of Settlements, Metering, and Client Relations Revenue Requirement

	CRS	ETS	FS	CM	MU	SMCR	Total
Functional Association of Settlements, Metering, and Client Relations	0.0%	70.34%	0.0%	8.23%	21.43%	0.0%	100.0%

Part F – Other Modifications to the Rates

Consistent with a Settlement Agreement accepted by the FERC in Docket Nos. ER04-115-000, et al., GMC rates and charges shall be calculated consistent with the following additional requirements during the period that the GMC rates and charges specified in that Settlement Agreement remain in effect:

1. The GMC chargeable to a Scheduling Coordinator for transactions representing transfers from the Mohave generation facility to the Loads of the Mohave co-owners located outside of the ISO Control Area, will be reduced by excluding 65 percent of those Loads from the Energy Transmission Services Net Energy Charge and the Core Reliability Services – Energy Exports Charge. Such excluded Load shall not be included in the denominators used to calculate the rates for the Energy Transmission Services – Net Energy Charge and the Core Reliability Services – Energy Export Charge.

2. The Forward Scheduling Charge assessed against Schedules submitted by PG&E solely in its role as Path 15 facilitator will be reduced by excluding 65 percent of the number of such Schedules from the Forward Scheduling Charge. Such excluded Schedules shall not be included in the denominator upon which the Forward Scheduling Charge is calculated.

3. Modesto Irrigation District (MID) is a Scheduling Coordinator and also is responsible for a portion of the GMC charges payable by another Scheduling Coordinator, Pacific Gas and Electric Company (PG&E) pursuant to a contract between them. MID and PG&E have agreed that MID shall pay the ISO directly $75,000 each month, in lieu of any payments to PG&E for its share of the GMC charges payable by PG&E and the ISO shall credit a portion of the amount received from MID to PG&E as an offset to PG&E’s obligation for GMC charges. Any difference, positive or negative, between the amount credited to PG&E and the amount paid by MID to the ISO under this provision shall be reflected in the Operating and Capital Reserves Account. The payment arrangement described in this paragraph is subject to the conditions, and will be implemented pursuant to the procedures, set forth in the Offer of Partial Settlement accepted by the FERC in Docket Nos. ER04-115-000, et al. This arrangement shall not apply to MID’s obligation for GMC charges as a Scheduling Coordinator, which shall be governed by the provisions of this Schedule 1 and the other applicable provisions of the ISO Tariff, except that in the event that MID accepts responsibility for scheduling any load currently scheduled by PG&E

under SCID PGAB, the ISO will not charge any additional GMC at the tariffed GMC rate, but rather will attribute such schedules and load to the fixed $75,000.00 per month payment set forth above, provided that MID schedules such load under a new and separate SCID and the ISO shall not assess GMC charges to such SCID..

any of which may submit comments and objections to the ISO within two weeks of the date of posting of the draft on the ISO Home Page.

SABP 2.3.4 Final Payments Calendar

No later than October 31st in each year, the ISO will publish pursuant to Section 11.24.1 of the ISO Tariff the final ISO Payments Calendar for the following calendar year, after considering the comments and objections received from Scheduling Coordinators, Black Start Generators, Participating TOs and Owners. The final ISO Payments Calendar will be posted on the ISO Home Page.

SABP 2.3.5 Update the Final Payments Calendar

If as a result of a tariff amendment approved by FERC the final ISO Payments Calendar developed in accordance with SABP 2.3.3 and 2.3.4 above is rendered inconsistent with the timing set forth in the tariff, the ISO shall update the final ISO Payments Calendar to make it consistent with the tariff as approved by FERC on the date on which the tariff amendment goes into effect. The ISO shall simultaneously send out a notice to Market Participants that the final ISO Payments Calendar has been revised.

SABP 2.3.6 Final Calendar Binding

The final ISO Payments Calendar shall be binding on the ISO and on Scheduling Coordinators, Black Start Generators, Participating TOs and Owners.

SABP 3 COMPUTATION OF CHARGES

SABP 3.1 Description of Charges to be Settled

The ISO shall, based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, calculate the following:

(a) the amount due from each Scheduling Coordinator for its share for the relevant month of the eight components of the Grid Management Charge in accordance with the formula located in Appendix F, Schedule 1, Part A of this Tariff. These Charges shall accrue on a monthly basis.

(b) the amount due from each Scheduling Coordinator for the Grid Operations Charge in accordance with Appendix F, Schedule 2 of this Tariff. This charge shall accrue on a monthly basis.

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day.

(d) amounts required with respect to payment adjustments for regulating Energy as calculated in accordance with Section 2.5.27.1 of the ISO Tariff. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh for that Trading Day.

SABP 3.2 Method of Settlement of Charges

SABP 3.2.1 Settlement of Payments to/from Scheduling Coordinators and Participating TOs

The ISO will calculate for each charge the amounts payable by the relevant Scheduling Coordinator, Black Start Generator or Participating TO for each Settlement Period of the Trading Day, and the amounts payable to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for each Settlement Period of that Trading Day and shall arrive at a net amount payable for each charge by or to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for that Trading Day. Each of these amounts will appear in the Preliminary and Final Settlement Statements that the ISO will provide to the relevant Scheduling Coordinator, Black Start Generator or Participating TO as provided in SABP 4.

The eight components of the Grid Management Charge will be included in the Preliminary Settlement Statement and Final Settlement Statement with the other types of charges referred to in SABP 3.1, but a separate invoice for the Grid Management Charge, stating the rate, billing determinant volume, and total charge for each of its eight components, will be issued by the ISO to the Scheduling Coordinator.

SABP 4 SETTLEMENT STATEMENTS

SABP 4.1 Preliminary Settlement Statements

SABP 4.1.1 Timing of Preliminary Settlement Statements

The ISO shall provide to each Scheduling Coordinator, Black Start Generator or Participating TO for validation a Preliminary Settlement Statement for each Trading Day in accordance with the ISO Payments Calendar.

A separate invoice for the Grid Management Charge, stating the rate, billing determinant volume and total charge for each of its eight components, will be issued by the ISO to the Scheduling Coordinator.

A separate invoice for Interest, issued on the preliminary invoice date, stating the total charges for each Trade Month in which interest is charged, will be issued by the ISO.

SABP 6 PAYMENT PROCEDURES

SABP 6.1 Time of Payment

SABP 6.1.1 Payment Date

Subject to SABP 6.1.2, payment will be made by the ISO and by each Scheduling Coordinator, Black Start Generator and Participating TO on the Payment Date as set forth in Section 11.3.2. Payment will be made by the ISO in accordance with Section 11.13.

SABP 6.1.2 Prepayments

(a) A Scheduling Coordinator may choose to pay at an earlier date than the Payment Date specified in the ISO Payments Calendar by way of prepayment provided it notifies the ISO by electronic means before submitting its prepayment.

(b) Prepayment notifications must specify the dollar amount prepaid.

(c) Prepayments must be made by Scheduling Coordinators via Fed-Wire into their ISO prepayment account designated by the ISO. The relevant Scheduling Coordinator shall grant the ISO a security interest on all funds in its ISO prepayment account.

(d) On any Payment Date the ISO shall be entitled to cause funds from the relevant Scheduling Coordinator's ISO prepayment account to be transferred to the ISO Clearing Account in such amounts as may be necessary to discharge in full that Scheduling Coordinator's payment obligation arising in relation to that Payment Date.

(e) Any funds held in the relevant Scheduling Coordinator's ISO prepayment account shall be treated as part of that Scheduling Coordinator's Security.

(f) Interest (or other income) accruing on the relevant Scheduling Coordinator's ISO prepayment account shall inure to the benefit of that Scheduling Coordinator and shall be added to the balance of its ISO prepayment account on a monthly basis.

(g) Funds held in an ISO prepayment account by a Scheduling Coordinator may be recouped, offset or applied by the ISO to any outstanding financial obligations of that Scheduling Coordinator to the ISO or to other Scheduling Coordinators under this Protocol.

Attachment A
Part 2

Revised ISO Tariff Sheets
Presuming Commission Approval of ISO Tariff Amendment 54 Prior to Approval of Offer of Partial Settlement

Energy Export	For purposes of calculating the Grid Management Charge, Energy included in an interchange Schedule submitted to the ISO, or dispatched by the ISO, to serve a Load located outside the ISO's Control Area, whether the Energy is produced by a Generator in the ISO Control Area or a resource located outside the ISO's Control Area.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.
Ex Post Price	The Hourly Ex Post Price, the Dispatch Interval Ex Post Price, the Resource-Specific Settlement Interval Ex Post Price, or the Zonal Settlement Interval Ex Post Price.
Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.

Attachment B
Part 1

Blacklined Revised ISO Tariff Sheets

8. GRID MANAGEMENT CHARGE.

8.1 ISO's Obligations.

8.1.1 FERC's Uniform System of Accounts.

The ISO shall maintain a set of financial statements and records in accordance with the FERC's Uniform System of Accounts.

8.1.2 [Not Used]

8.2 Costs Included in the Grid Management Charge.

8.2.1 [Not Used]

8.2.2 Operating Costs.

Budgeted annual operating costs, which shall include all staffing costs including remuneration of contractors and consultants, salaries, benefits and any incentive programs for employees, costs of operating, replacing and maintaining ISO systems, lease payments on facilities and equipment necessary for the ISO to carry out its business, and annual costs of financing the ISO's working capital and other operating costs ("Operating Costs").

8.2.3 Financing Costs.

The financing costs that are approved by the ISO Governing Board, including capital expenditures that may be financed over such period as the ISO Governing Board shall decide. Financing Costs shall also include the ISO start up and development costs standing to the credit of the ISO Memorandum Account plus any additional start up or development costs incurred after the date of Resolution E-3459 (July 17, 1996), plus any additional capital expenditure incurred by the ISO in 1998 ("Start Up and Development Costs"). The amortized amount to be included in the Grid Management Charge shall be equal to the amount necessary to amortize fully all Start Up and Development Costs over a period of five (5) years, or such longer period as the ISO Governing Board shall decide ("Financing Costs").

8.2.4 Operating and Capital Reserves Cost.

The budgeted annual cost of pay-as-you-go capital expenditures and reasonable coverage of debt service obligations. Such reserves shall be utilized to minimize the impact of any variance between forecast and actual costs throughout the year ("Operating and Capital Reserves Costs").

8.3 Allocation of the Grid Management Charge Among Scheduling Coordinators.

The costs recovered through the Grid Management Charge shall be allocated to the ~~seven~~ eight service charges that comprise the Grid Management Charge. If the ISO's revenue requirement for any service charge changes from the most recent FERC-approved revenue requirement for that service charge, the costs recovered through that service charge shall be delineated in a filing to be made at FERC as set forth in Section 8.4. The ~~seven~~ eight service charges are as follows:

(1) Core Reliability Services - Demand Charge,

(2) Core Reliability Services – Energy Exports Charge

(3) Energy Transmission Services Net Energy Charge,

(~~3~~4) Energy Transmission Services Uninstructed Deviations Charge,

(~~4~~5) Forward Scheduling Charge,

(~~5~~6) Congestion Management Charge,

(~~6~~7) Market Usage Charge, and

(~~7~~8) Settlements, Metering, and Client Relations Charge.

The ~~seven~~ eight charges shall be levied separately monthly in arrears on all Scheduling Coordinators based on the billing determinants specified below for each charge in accordance with formulae set out in Appendix F, Schedule 1, Part A of this Tariff, subject to the requirements set out in Appendix F, Schedule 1, Part F of this Tariff.

8.3.1 Core Reliability Services – Demand Charge.

The Core Reliability Services – Demand Charge for a Scheduling Coordinator's Load that is not associated with Energy Exports is calculated using the Scheduling Coordinator's metered non-coincident peak hourly Demand during the month (in megawatts) less the volume of Energy Exports included in the Scheduling Coordinator's non-coincident peak hourly Demand for the month, if any; provided that if the Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400 the rate shall be sixty-six (66) percent of the standard CRS rate. The standard rate for the Core Reliability Services – Demand Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total of the forecasted metered non-coincident peak hourly Demand for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peak hour during the month occurs between the hour ending 2300 and the hour ending 0600, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.2 Core Reliability Services – Energy Exports Charge,

The Core Reliability Services – Energy Exports Charge for the load associated with a Scheduling Coordinator's Energy Exports is calculated using the Scheduling Coordinator's metered volume of Energy Exports (in megawatt-hours); The rate for the Core Reliability Services – Energy Exports Charge is determined by dividing the GMC costs allocated to the Core Reliability Services service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.~~2~~3 Energy Transmission Services Net Energy Charge.

The Energy Transmission Services Net Energy Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's Metered Control Area Load (in megawatt-hours). The rate for the Energy Transmission Services Net Energy Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Metered Control Area Load, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.~~3~~4 Energy Transmission Services Uninstructed Deviations Charge.

The Energy Transmission Services Uninstructed Deviations Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's net uninstructed deviations by Settlement Interval. The rate for the Energy Transmission Services Uninstructed Deviations Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted net uninstructed deviations by Settlement Interval according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.4~~5~~ Forward Scheduling Charge.

The Forward Scheduling Charge for each Scheduling Coordinator is calculated using the sum of that Scheduling Coordinator's Final Hour-Ahead Schedules, including all awarded Ancillary Services bids, with a value other than 0.03 MW~~, submitted to the scheduling infrastructure/scheduling application system~~. The Forward Scheduling Charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinating Energy and Ancillary Service Trades for each Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge. The rate for the Forward Scheduling Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Final Hour-Ahead Schedules and awarded Ancillary Service bids submitted to the ISO, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.~~5~~6 Congestion Management Charge.

The Congestion Management Charge for each Scheduling Coordinator is calculated as the product of the rate for the Congestion Management Charge and the absolute value of the net scheduled inter-zonal flow (excluding flows pursuant to Existing Contracts) per path for that Scheduling Coordinator. The rate for the Congestion Management Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.~~6~~7 Market Usage Charge.

The Market Usage Charge for each Scheduling Coordinator is calculated using the absolute value of the Scheduling Coordinator's market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval). The rate for the Market Usage Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted number of market purchases and sales, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.~~7~~8 Settlements, Metering, and Client Relations Charge.

The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at $500.00 per month, per Scheduling Coordinator ID with an invoice value other than $0.00 in the current trade month, as indicated in Appendix F, Schedule 1, Part A of this Tariff. Excess GMC costs related to the provision of these services that are not recovered through this charge are allocated to the other GMC service categories as specified above and in Appendix F, Schedule 1, Part E of this Tariff.

8.4 Calculation and Adjustment of the Grid Management Charge.

The ~~seven~~ eight charges set forth in Section 8.3 that comprise the Grid Management Charge shall be calculated through the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The formula set forth in Appendix F, Schedule 1, Part C of this Tariff sums the Operating Costs (less any available expense recoveries), Financing Costs, and Operating and Capital Reserves Costs associated with each of the ~~seven~~ eight ISO service charges to obtain a total revenue requirement. This revenue requirement is allocated among the ~~seven~~ eight charges of the GMC through the application of the factors specified in Appendix F, Schedule 1, Part E of this Tariff.

The revenue requirement for each service then shall be divided by the forecast annual or periodic billing determinant volume to obtain a rate for each service, which will be payable by Scheduling Coordinators as set forth in Section 8.3. The rates so established will be adjusted annually, through the operation of the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The ISO shall post on its website each year~~make an informational filing with the FERC each year~~, before the adjusted rates go into effect, as described in Appendix F, Schedule 1, Part D of this Tariff, data showing the rates adjusted to reflect any change in the annual revenue requirement, variance between forecast and actual costs for the previous year or period, or any surplus revenues from the previous year or period (as defined in Section 8.5), or the inability to recover from a Scheduling Coordinator its share of the Grid Management Charge, or any under-achievement of a forecast of the billing determinant volumes used to establish the rates. The circumstances under which the ISO is permitted to put the adjusted rates into effect without submitting a filing to the FERC are described in Appendix F, Schedule 1, Part D of this Tariff. Appendix F, Schedule 1, Part B of this Tariff sets forth the conditions under which a quarterly adjustment to the Grid Management Charge will be made.

8.4.1 Credits and Debits of the Grid Management Charge.

In addition to the adjustments permitted under Section 11.6.3.3, the ISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any overpayment or underpayment of the Grid Management Charge that the ISO determines occurred due to error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

8.5 Operating and Capital Reserves Account.

Revenues collected to fund the ISO financial operating reserves shall be deposited in an Operating and Capital Reserves Account until such account reaches a level specified by the ISO Governing Board. The Operating and Capital Reserves Account shall be calculated separately for each GMC service category (Core Reliability Services - Demand, Core Reliability Services –

Energy Export, Energy Transmission Services – Net Energy, Energy Transmission Services – Uninstructed Deviations, Forward Scheduling, Congestion Management, Market Usage, and Settlements, Metering and Client Relations). The allocation factors, reassignments and reallocations specified in Schedule 1, Parts E and F, will be accounted for in the development of the Operating and Capital Reserves Account for each component. If the Operating and Capital Reserves Account as calculated for such service category is fully funded, surplus funds will be considered an offset to the revenue requirement of the next fiscal year.

8.6 Transition Mechanism.

During the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, the Original Participating TOs collectively shall pay to the ISO each year an amount equal to, annually, for all New Participating TOs, the amount, if any, by which the New Participating TO's cost of Existing High Voltage Facilities associated with deliveries of Energy to Gross Loads in the PTO Service Territory of the New Participating TO is increased by the implementation of the High Voltage Access Charge described in Schedule 3 to Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in accordance with Schedule 3 to Appendix F. Amounts payable by Original Participating TOs under this section shall be recoverable as part of the Transition Charge calculated in accordance with Schedule 3 of Appendix F. Amounts received by the ISO under this section shall be disbursed to New Participating TOs with Existing High Voltage Facilities based on the ratio of each New Participating TO's net increase in costs in the categories described in the first sentence of this section, to the sum of the net increases in such costs for all New Participating TOs with Existing High Voltage Facilities.

* * *

ISO TARIFF APPENDIX A

Master Definitions Supplement

Congestion Management Charge	The component of the Grid Management Charge that provides

for the recovery of the ISO's costs of operating the Congestion Management process including, but not limited to, the management and operation of Inter-Zonal Congestion markets, Adjustment Bids, taking Firm Transmission Rights and Existing Contracts into account, and determining the price for mitigating Congestion for flows on Congested paths. The formula for determining the Congestion Management Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Control Area Gross Load

For the purpose of calculating and billing Minimum Load Costs, Emission Costs Charge and Start-Up Fuel Costs Charge, Control Area Gross Load is all Demand for Energy within the ISO Control Area. Control Area Gross Load shall not include Energy consumed by:

(a) generator auxiliary Load equipment that is dedicated to the production of Energy and is electrically connected at the same point as the Generating Unit (*e.g.*, auxiliary Load equipment that is served via a distribution line that is separate from the switchyard to which the Generating Unit is connected will not be considered to be electrically connected at the same point); and

(b) Load that is isolated electrically from the ISO Control Area (*i.e.*, Load that is not synchronized with the ISO Control Area).

Core Reliability Services – Demand Charge

~~The~~A component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Demand Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Core Reliability Services – Energy Export Charge

A component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Energy Exports Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Energy Transmission Services Net Energy Charge

The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Uninstructed Deviations Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, i.e., a function of the intensity of the use of the transmission system within the Control Area and the occurrence of system outages and disruptions. The formula for determining the Energy Transmission Services Net Energy Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Energy Transmission Services Uninstructed Deviations Charge

The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Net Energy Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, in particular for the costs associated with balancing transmission flows that result from uninstructed deviations. The formula for determining the Energy Transmission Services Uninstructed Deviations Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Energy Export — For purposes of calculating the Grid Management Charge, Energy included in an interchange Schedule submitted to the ISO, or dispatched by the ISO, to serve a Load located outside the ISO's Control Area, whether the Energy is produced by a Generator in the ISO Control Area or a resource located outside the ISO's Control Area.

Forward Scheduling Charge — The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of providing the ability to Scheduling Coordinators to forward schedule Energy and Ancillary Services and the cost of processing accepted Ancillary Service bids. For purposes of the Forward Scheduling Charge, a schedule is represented by each Final Hour-Ahead Schedule with a value other than 0 MW submitted to the scheduling infrastructure/scheduling application system (import, export, Load, Generation, inter-Scheduling Coordinator trade, and Ancillary Services, including self-provided Ancillary Services) submitted to the ISO's scheduling infrastructure. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Grid Management Charge — The ISO monthly charge on all Scheduling Coordinators that provides for the recovery of the ISO's costs listed in Section 8.2 through the ~~seven~~eight service charges described in Section 8.3 calculated in accordance with the formula rate set forth in Appendix F, Schedule 1, Part A of this Tariff. The ~~seven~~ eight charges that comprise the Grid Management Charge consist of: 1) the Core Reliability Services - Demand Charge, 2) the Core Reliability Services – Energy Exports Charge, 3) the Energy Transmission Services Net Energy Charge, ~~3~~4) the Energy Transmission Services Uninstructed Deviations Charge, ~~4~~5) the Forward Scheduling Charge, ~~5~~6) the Congestion Management Charge, ~~6~~7) the Market Usage Charge, and ~~7~~8) the Settlements, Metering, and Client Relations Charge.

Market Usage Charge

The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs for processing Supplemental Energy and Ancillary Service bids, maintaining the Open Access Same-Time Information System, monitoring market performance, ensuring generator compliance with market protocols, and determining Market Clearing Prices. The formula for determining the Market Usage Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Metered Control Area Load

For purposes of calculating and billing the ~~Energy Transmission Services Net Energy Charge component of the~~

Grid Management Charge, Metered Control Area Load is: (a) all metered Demand for Energy of Scheduling Coordinators for the supply of Loads in the ISO's Control Area, plus (b) all Energy for exports by Scheduling Coordinators from the ISO Control Area; less (c) Energy associated with the Load of a retail customer of a Scheduling Coordinator, UDC, or MSS that is served by a Generating Unit that: (i) is located on the same site as the customer's Load or provides service to the customer's Load through arrangements as authorized by Section 218 of the California Public Utilities Code; (ii) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (iii) the customer secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or the customer's Load can be curtailed concurrently with an outage of the Generating Unit.

Settlements, Metering, and Client Relations Charge

The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of maintaining customer account data, providing

account information to customers, responding to customer inquiries, calculating market charges, resolving customer disputes, and the costs associated with the ISO's Settlement, billing, and metering activities. Because this is a fixed charge per Scheduling Coordinator ID, costs associated with activities listed above also are allocated to other charges under the Grid Management Charge according to formula set forth in Appendix F, Schedule 1, Part A of this Tariff.

ISO TARIFF APPENDIX F

Rate Schedules

Schedule 1

Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of ~~seven~~eight separate service charges: (1) the Core Reliability Services – Demand Charge, (2) the Core Reliability Services – Energy Exports Charge, 3) the Energy Transmission Services Net Energy Charge, (~~3~~4) the Energy Transmission Services Uninstructed Deviations Charge, (~~4~~5) the Forward Scheduling Charge, (~~5~~6) the Congestion Management Charge, (~~6~~7) the Market Usage Charge, and (-87) the Settlements, Metering, and Client Relations Charge.

1. The rate in $/MW for the Core Reliability Services – Demand Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any, as may be modified in accordance with Part F of this Schedule 1), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peaks occurring during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and holidays; provided that if a Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, the rate shall be sixty-six (66) percent of the standard Core Reliability Services – Demand rate.

2. The rate in $/MWh for the Core Reliability Services – Energy Export Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered volume of Energy Exports

in MWh, as may be modified in accordance with Part F of this Schedule 1, for all months during the year.

~~2~~3. The rate in $/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Control Area Load ~~in MWh~~.

~~3~~4. The rate in $/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net uninstructed deviations (netted within a Settlement Interval summed over the calendar month) in MWh.

~~4~~5. The rate in $ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Final Hour-Ahead Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service bids; provided that the Forward Scheduling charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades for each Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge.

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~~5~~6. The rate in $/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

~~6~~7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted within a ~~by~~ Settlement Interval summed over the calendar month) in MWh.

~~7~~8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $500.00 per month, per Scheduling Coordinator Identification Number (“SC ID”) with an invoice value other than $0.00 in the current trade month.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the ISO's ~~annual informational~~ filing or posting on the ISO Home Page, as applicable, if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted in accordance with the following formula:

According to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the 5% or greater change from the estimated billing determinant provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 8 of the ISO Tariff, the Grid Management Charge includes the following costs, as projected in the ISO's budget for the year to which the Grid Management Charge applies:

- Operating costs (as defined in Section 8.2.2)
- Financing costs (as defined in Section 8.2.3), including Start-Up and Development costs and
- Operating and Capital Reserve costs (as defined in Section 8.2.4)

Such costs, for the ISO as a whole, are allocated to the ~~seven~~ eight service charges that comprise the Grid Management Charge: (1) Core Reliability Services – Demand Charge, (2) Core Reliability Services – Energy Export Charge, (3) Energy Transmission Services Net Energy Charge, (~~3~~4) Energy Transmission Services Uninstructed Deviations Charge, (~~4~~5) Forward Scheduling Charge, (~~5~~6) Congestion Management Charge, (~~6~~7) Market Usage Charge, and (~~7~~8) Settlements, Metering, and Client Relations Charge, according to the factors listed in Part E of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the Operating and Capital Reserve Account, as defined under Section 8.5, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual Grid Management Charge components, if, on an annual basis, the change is 5% or more.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

- Operating Expenses + Debt Service + [(Coverage Requirement x Senior Lien Debt Service) and/or (Cash Funded Capital Expenditures)] - Interest Earnings - Other Revenues - Reserve Transfer

Where,

- **Operating Expenses** = O&M Expenses plus Taxes Other Than Income Taxes and Penalties
- **O&M Expenses** = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- **Taxes Other Than Income Taxes** = those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- **Penalties** = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- **Debt Service** = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- **Coverage Requirement** = 25% of the Senior Lien Debt Service.
- **Senior Lien Debt Service** = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- **Cash Funded Capital Expenditures** = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.

- **Interest Earnings** = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.

- **Other Revenues** = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC reliability coordinator reimbursements, and fines assessed and collected by the ISO.

- **Reserve Transfer** = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)

- **Reserve Requirement** = 15% of Annual Operating Expenses.

A separate revenue requirement shall be established for each component of the Grid Management Charge by developing the revenue requirement for the ISO as a whole and then assigning such costs to the seven service categories using the allocation factors provided in Appendix F, Schedule 1, Part E of this Tariff.

Part D – Information Requirements

Budget Schedule

~~The ISO Governing Board shall set forth a budget schedule that shall specify the dates for the budget posting and public workshop events noted below and other significant budget related milestones providing an opportunity for public input.~~

The ISO will convene, prior to the commencement of the Annual Budget process, an initial meeting with stakeholders to: (a) receive ideas to control ISO costs; (b) receive ideas for projects to be considered in the capital budget development process; and, (c) receive suggestions for reordering ISO priorities in the coming year.

Within 2 weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the ISO's officers, directors and managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

Subsequent to the initial submission of the draft budget to the finance committee of the ISO Governing Board, the ISO will provide stakeholders with the following information: (a) proposed capital budget with indicative projects for the next subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the ISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. Certain of this detailed information which is deemed commercially sensitive will only be made available to parties that pay the ISO's GMC (or regulators) who execute a confidentiality agreement.

The ISO shall provide such materials on a timely basis to provide stakeholders at least one full committee meeting cycle to review and prepare comments on the draft annual budget to the finance committee of the ISO Governing Board.

At least one month prior to the ISO Governing Board meeting scheduled to consider approval of the proposed budget, the ISO will hold a meeting open to all stakeholders to discuss the details of the ISO's budget and revenue requirement for the forthcoming year. To the extent that such a meeting will deal with complex matters of budgetary and policy import, the ISO will endeavor to host a workshop on the ISO's budget preparation process in advance of the meeting to better prepare stakeholders.

Prior to a final recommendation by the finance committee of the ISO Governing Board on the ISO's draft annual budget, the ISO shall respond in writing to all written comments on the draft annual budget submitted by stakeholders and/or the ISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

The ISO will provide no fewer than 45 days for stakeholder review of its annual budget between initial budget posting and final approval of the budget by the ISO Governing Board.

Budget Posting

After the approval of the annual budget by the ISO Governing Board, ~~T~~the ISO will post on its Internet site the ~~preliminary proposed~~ ISO operating and capital budget to be effective during the subsequent fiscal year, and the ~~projected~~ billing determinant volumes used to develop the rate for each component of the Grid Management Charge, together with workpapers showing the calculation of such rates.

~~Public Workshop~~

~~Subsequent to the website posting, and prior to (i) the ISO Governing Board approval of the budget and (ii) the submission of the informational filing described in the next paragraph of this Part D, the ISO shall hold a public budget workshop where it will provide an overview of and answer questions from stakeholders on the proposed budget, cost allocation, and the charges for each of the ISO's services for the following year.~~

Annual ~~Informational~~ Filing

~~The ISO will make a filing each year no later than December 15, or the first Business Day thereafter, at FERC that shall contain projected cost data on the ISO presented in conformance with the budget approved by the ISO Governing Board and the FERC Uniform System of Accounts (USOA). This filing shall contain such information as is required to update the GMC rates resulting from the application of the formulae in Part A of this Schedule for the following calendar year.~~

If the Grid Management Charge revenue requirement for Budget Year 2005 does not exceed $218.4 million or its revenue requirement for Budget Year 2006 does not exceed $221.7 million, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to collect such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for Budget Year 2005 that exceeds $218.4 million or Budget Year 2006 that exceeds $221.7 million, the ISO must submit an application to the FERC under Section 205. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective as of January 1, 2007. In such filing, the ISO may revise the GMC rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

The ISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the ISO Governing Board. The periodic financial reports will be posted on the ISO's Website not less than quarterly.

Part E – Cost Allocation

1. The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the ~~seven~~ eight service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E. Expenses projected to be recorded in each cost center shall be allocated among the ~~seven~~eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. In the event the ISO budgets for projected expenditures for cost centers are not specified in Table 1 to ~~this~~ Schedule 1, such expenditures shall be allocated based on the allocation factors for the respective ISO division hosting that newly-created cost center. Such divisional allocation factors are specified in Table 1 to this Schedule 1.

Debt service expenditures for the ISO's year 2000 (or subsequently refinanced) bond offering shall be allocated among the ~~seven~~eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. Capital expenditures shall be allocated among the ~~seven~~eight charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E, for the system for which the capital expenditure is projected to be made.

Any costs allocated by the factors listed in Table 1 and Table 2 to the Settlements, Metering, and Client Relations category that would remain un-recovered after the assessment of the charge for that service specified in Section ~~7~~8 of Part A of this Schedule 1 on forecasted billing determinant volumes shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

2. The allocation of costs in accordance with Section 1 and Tables 1 and 2 of this Part E shall be adjusted as follows:

Costs allocated to the Energy Transmission Services category in the following tables are further apportioned to the Energy Transmission Services Net Energy and Energy Transmission Services Uninstructed Deviations subcategories in 80% and 20% ratios, respectively.

Twenty (20) percent of the costs allocated to the Forward Scheduling Charge in the following Tables shall be reallocated to the Congestion Management Charge. A portion of the costs allocated to the Forward Scheduling Charge, associated with the fifty (50) percent reduction in the standard Forward Scheduling Charge to be applied to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades as specified in Part A of this Schedule 1, shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

Table 1

O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC #	Cost Center	CRS	ETS	FS	CM	MU	SMCR	Total
1100	**CEO Division**	**44.01%**	**2~~2~~1.51%**	**~~4~~3.78%**	**~~5~~4.61%**	**10.45%**	**1~~6~~5.63%**	**100%**
1111	CEO - General	44.01%	~~22~~21.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1241	MD02	~~7~~6.95%	0%	1~~4~~3.86%	~~1~~10.91%	28.38%	~~40~~39.90%	100%
1521	Grid Planning	6~~3~~2.50%	3~~8~~7.50%	0%	0%	0%	0%	100%
1300	**Finance Division**	**44.04%**	**21.49%**	**~~4~~3.62%**	**4.22%**	**10.31%**	**16.32%**	**100%**
1311	CFO - General	44.04%	21.49%	~~4~~3.62%	4.22%	10.31%	16.32%	100%
1321	Accounting	44.01%	2~~2~~1.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1331	Financial Planning and Treasury	44.01%	2~~2~~1.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1351	Facilities	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
1361	Security & Corporate Services	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
1400	**Information Services Division**	**38.25%**	**7.16%**	**~~10~~9.74%**	**~~5~~4.78%**	**9.23%**	**3~~1~~0.85%**	**100%**
1411	Chief Information Officer	38.25%	7.16%	~~10~~9.74%	~~5~~4.78%	9.23%	3~~1~~0.85%	100%
1422	Corporate &	33.28	7.06%	1.16	25.28	1~~3~~2.58	2~~1~~0.63	100%

	Enterprise Applications	%		%	%	%	%	
1424	Asset Management	35.30%	6.12%	1~~1~~0.91%	~~5~~4.88%	1~~1~~0.50%	32.29%	100%
1431	End User Support	3~~8~~7.80%	14.44%	8.29%	3.5%	9.32%	2~~7~~6.65%	100%
1432	Computer Operations and Infrastructure Services	34.15%	9.21%	1~~2~~1.76%	3.08%	~~9~~8.69%	33.11%	100%
1433	Network Services	43.38%	1~~2~~1.88%	9.39%	~~3~~2.61%	9.23%	2~~4~~3.51%	100%
1441	Outsourced Contracts	42.25%	1~~1~~0.62%	10.25%	~~3~~2.53%	9.07%	25.28%	100%
1442	Production Support	25.09%	0.17%	1~~8~~7.98%	~~3~~2.62%	~~8~~7.52%	4~~7~~6.62%	100%
1451	Information Support Services	25.09%	0.17%	1~~8~~7.98%	~~3~~2.62%	~~8~~7.52%	4~~7~~6.62%	100%
1461	Control Systems	96.44%	2.44%	0%	0%	~~1~~0.56%	~~1~~0.56%	100%
1462	Field Data Acquisition System (FDAS)	21.43%	0%	0%	0%	0%	7~~9~~8.57%	100%
1463	Operations Systems Services	50.44%	~~3~~2.91%	6.01%	1.21%	~~6~~5.95%	33.49%	100%
1466	Enterprise Applications	4~~8~~7.98%	7.30%	1.19%	1.34%	3.47%	3~~9~~8.72%	100%
1467	Settlement Systems Services	27.34%	11.20%	~~2~~1.83%	2.05%	5.32%	52.25%	100%
1468	Corporate Application Support and Administration	44.06%	21.47%	4~~%~~3.51	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
1469	Analytical and Reporting Applications	10%	0%	0%	65%	25%	0%	100%
1471	IT Planning	25.09%	0.17%	1~~8~~7.98%	~~3~~2.62%	~~8~~7.52%	4~~7~~6.62%	100%
1481	Markets and Scheduling System Services	4~~7~~6.85%	~~3~~2.86%	2~~4~~3.68%	~~3~~2.5%	1~~8~~7.64%	6.48%	100%
1482	Market Systems Support Services	4~~5~~4.94%	1.05%	1~~9~~8.51%	6.17%	2~~4~~3.78%	~~6~~5.54%	100%

1500	**Grid Operations Division**	**6~~7~~6.71%**	**33.29%**	**0%**	**0%**	**0%**	**0%**	**100%**
1511	VP Grid Operations	6~~7~~6.71%	33.29%	0%	0%	0%	0%	100%
1542	Outage Coordination	95.11%	~~5~~4.89%	0%	0%	0%	0%	100%
1543	Loads and Resources	4~~9~~8.95%	51.05%	0%	0%	0%	0%	100%
1544	Real-Time Scheduling	60%	40%	0%	0%	0%	0%	100%
1545	Grid Operations	67.47%	3~~3~~2.53%	0%	0%	0%	0%	100%
1546	Security Coordination	100%	0%	0%	0%	0%	0%	100%
1547	Engineering and Maintenance	46.42%	5~~4~~3.58%	0%	0%	0%	0%	100%
1548	OSAT Group - General	93.2%	~~7~~6.80%	0%	0%	0%	0%	100%
1549	Operations Training	50.48%	~~50~~49.52%	0%	0%	0%	0%	100%
1554	Special Projects Engineering	4~~3~~2.86%	57.14%	0%	0%	0%	0%	100%
1555	Operations Support Group	5~~6~~5.56%	44.44%	0%	0%	0%	0%	100%
1558	Transmission Maintenance	58.46%	4~~2~~1.54%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65.32%	3~~5~~4.68%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55.15%	4~~5~~4.85%	0%	0%	0%	0%	100%
1563	Operations Coordination	74.55%	25.45%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	7~~7~~6.92%	23.08%	0%	0%	0%	0%	100%
1566	Regional Coordination	100%	0%	0%	0%	0%	0%	100%

	General							
1600	**Legal and Regulatory Division**	**35.80~~6~~%**	**2~~2~~1.78%**	**~~4~~3.73%**	**7.18%**	**1~~7~~6.97%**	**1~~5~~4.54%**	**100%**
1611	VP General Counsel - General	3~~6~~5.80%	2~~2~~1.78%	~~4~~3.73%	7.18%	1~~7~~6.97%	1~~5~~4.54%	100%
1631	Legal and Regulatory	44.01%	2~~2~~1.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1641	Market Analysis	15.32%	26.33%	0%	~~20~~19.90%	31.38%	7.07%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44.01%	2~~2~~1.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1661	Compliance - General	2~~2~~1.90%	20.37%	1~~2~~1.90%	0%	2~~9~~8.50%	17.33%	100%
1662	Compliance - Audits	8.33%	0%	0%	0%	50%	4~~2~~1.67%	100%
1700	**Market Services Division**	**17.14%**	**2.43%**	**9.46%**	**9.39%**	**20.35%**	**41.23%**	**100%**
1711	VP Market Services - General	17.14%	2.43%	9.46%	9.39%	20.35%	41.23%	100%
1721	Billing and Settlements-General	25%	0%	0%	0%	0%	75%	100%
1722	Business Development Support	0%	0%	0%	0%	0%	100%	100%
1723	RMR Settlements	80.30%	~~20~~19.70%	0%	0%	0%	0%	100%
1724	BBS - PSS	0%	0%	0%	0%	0%	100%	100%
1725	BBS - FSS	0%	0%	0%	0%	0%	100%	100%
1731	Contracts and Special Projects	43.17%	~~7~~6.83%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	3~~1~~0.66%	0%	15.33%	15.33%	3~~5~~4.85%	~~4~~3.83%	100%
1752	Manager of Markets	27.31%	5.46%	27.31%	2~~2~~1.84%	18.08%	0%	100%

1753	Market Engineering	21.32%	0%	0%	28.43%	43.15%	7.11%	100%
1755	Business Solutions	~~6~~5.91%	0%	47.27%	1~~2~~1.82%	29.10%	~~6~~5.91%	100%
1756	Market Quality - General	0%	0%	0%	0%	7~~1~~0.93%	29.07%	100%
1757	Market Integration	7.38%	0%	~~30~~29.52%	~~30~~29.52%	26.20%	7.38%	100%
1800	**Corporate and Strategic Development Division**	**44.04%**	**21.49%**	**~~4~~3.62%**	**4.21%**	**10.31%**	**16.33%**	**100%**
1811	VP Corporate and Strategic Development - General	44.04%	21.49%	~~4~~3.62%	4.21%	10.31%	16.33%	100%
1821	Communications	44.01%	22.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1831	Strategic Development	44.01%	22.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1841	Human Resources	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
1851	Project Office	44.01%	2~~2~~1.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
1861	Regulatory Policy	44.01%	2~~2~~1.51%	~~4~~3.78%	~~5~~4.61%	10.45%	1~~6~~5.63%	100%
Other Revenue and Credits								
	SC Application and Training Fees	0%	0%	0%	0%	0%	100%	100%
	WECC Reimbursement/NERC Reimbursement	100%	0%	0%	0%	0%	0%	100%
	Interest Earnings	3~~7~~6.64%	12.29%	9.34%	~~5~~4.97%	11.47%	25.30%	100%
Debt Service Related Allocations		33.49%	~~8~~7.93%	15.26%	5.19%	9.44%	2~~9~~8.69%	100%

Table 2

Capital Cost Allocation Factors

System	CRS	ETS	FS	CM	MU	SMCR	Total
ACC Upgrades (Communication between ISO & IOUs)	100%	0%	0%	0%	0%	0%	100%
Ancillary Services Management (ASM) Component of SA	15%	0%	40%	0%	45%	0%	100%
Application Development Tools	23.46%	0.18%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
Automated Dispatch System (ADS)	50%	0%	25%	0%	20%	5%	100%
Automated Load Forecast System (ALFS)	70%	0%	10%	0%	20%	0%	100%
Automatic Mitigation Procedure (AMP)	85%	0%	0%	0%	15%	0%	100%
Backup systems (Legato/Quantum)	23%	0%	22%	3%	7%	45%	100%
Balance of Business Systems (BBS)	0%	0%	0%	0%	0%	100%	100%
Balancing Energy Ex Post Price (BEEP) Component of SA	50%	0%	20%	10%	20%	0%	100%
Bill's Interchange Schedule (BITS)	85%	0%	0%	0%	15%	0%	100%
CaseWise (process modeling tool)	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
CHASE	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Common Information Model (CIM)	100%	0%	0%	0%	0%	0%	100%
Compliance (Blaze)	19.17%	16.27%	~~10~~9.5%	0%	3~~3~~2.83%	22.23%	100%
Congestion Management (CONG) (Component of SA)	10%	0%	0%	65%	25%	0%	100%
Congestion Reform-DSOW	50%	0%	0%	50%	0%	0%	100%

Congestion Revenue Rights (CRR)	0%	0%	0%	80%	20%	0%	100%
DataWarehouse	24.46%	18.27%	6.40%	~~9~~8.74%	24.30%	1~~8~~7.82%	100%
Dept. of Market Analysis Tools (SAS/MARS)	15.32%	26.33%	0%	~~20~~19.90%	31.38%	7.07%	100%
Dispute Tracking System (Remedy)	0%	0%	0%	0%	0%	100%	100%
Documentum	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Electronic Tagging (Etag)	100%	0%	0%	0%	0%	0%	100%
Energy Management System (EMS)	100%	0%	0%	0%	0%	0%	100%
Engineering Analysis Tools	60%	40%	0%	0%	0%	0%	100%
Evaluation of Market Separation	0%	0%	0%	50%	50%	0%	100%
Existing Transmission Contracts Calculator (ETCC)	25%	0%	20%	15%	20%	20%	100%
FERC Study Software	0%	0%	0%	0%	100%	0%	100%
Firm Transmission Right (FTR) and Secondary Registration System (SRS)	0%	0%	15%	60%	15%	10%	100%
Global Resource Reliability Management Application (GRRMA)	75%	15%	0%	0%	10%	0%	100%
Grid Operations Training Simulator (GOTS)	56%	44%	0%	0%	0%	0%	100%
Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,	0%	0%	100%	0%	0%	0%	100%
Human Resources	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
IBM Contract	37.26%	14.44%	~~10~~9.54%	~~4~~3.52%	9.10%	26.13%	100%
Integrated Forward Market (IFM)	10%	0%	35%	0%	55%	0%	100%

Internal Development	23.46%	0.18%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
Interzonal Congestion Management reform - Real Time	50%	0%	0%	50%	0%	0%	100%
Land and Building Costs	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Local Area Network (LAN)	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Locational Marginal Pricing (LMPM)	10%	0%	35%	0%	55%	0%	100%
Market Transaction System (MTS)	0%	0%	0%	0%	100%	0%	100%
Masterfile	20%	0%	20%	0%	55%	5%	100%
MD02 Capital	~~7~~6.95%	0%	1~~4~~3.86%	1~~1~~0.91%	28.38%	~~40~~39.90%	100%
Meter Data Acquisition System (MDAS)	0%	0%	0%	0%	0%	100%	100%
Miscellaneous (2004 related projects)	23.46%	0%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
Monitoring (Tivoli)	23.46%	0%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
New Resource Interconnection (NRI)	100%	0%	0%	0%	0%	0%	100%
New System Equipment (replacement of owned equipment)	23.46%	0.18%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
NT/web servers	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
NT-servers	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Oracle Enterprise Manager (OEM)	27%	0%	18%	5%	9%	41%	100%
Office Automation - desktop/laptop (OA)	44%	21%	4%	4%	10%	17%	100%
Office equipment (scanner, printer, copier, fax, Communication Equipment)	44%	21%	4%	4%	10%	17%	100%

Open Access Same Time Information System (OASIS)	10%	0%	25%	10%	35%	20%	100%
Operational Meter Analysis and Reporting (OMAR)	0%	0%	0%	0%	0%	100%	100%
Oracle Corporate Financials	44%	21%	4%	4%	10%	17%	100%
Oracle Licenses	27%	0%	18%	5%	9%	41%	100%
Oracle Market Financials BBS	0%	0%	0%	0%	0%	100%	100%
Out of Sequence Market Operation Settlements Information System (OOS)	5%	5%	0%	0%	90%	0%	100%
Outage Scheduler (OS)	50%	0%	10%	20%	20%	0%	100%
Participating Intermittent Resource Project (PIRP)	0%	0%	9~~4~~3.92%	0%	6.08%	0%	100%
Physical Facilities Software Application/Furniture/Leasehold Improvements	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Process Information System (PI)	80%	0%	0%	0%	10%	10%	100%
Rational Buyer	100%	0%	0%	0%	0%	0%	100%
Real Time Energy Dispatch System (REDS)	100%	0%	0%	0%	0%	0%	100%
Real Time Nodal Market	35%	0%	10%	0%	55%	0%	100%
Reliability Management System (RMS)	100%	0%	0%	0%	0%	0%	100%
Remedy (related to Transmission Registry, New Resource Interconnection, and Resource Registry)	100%	0%	0%	0%	0%	0%	100%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	100%	0%	0%	0%	0%	0%	100%
Resource Register (RR)	100%	0%	0%	0%	0%	0%	100%

RMR Application Validation Engine (RAVE)	100%	0%	0%	0%	0%	0%	100%
Scheduling & Logging for ISO California (SLIC)	65%	0%	15%	5%	15%	0%	100%
Scheduling Architecture (SA)	2~~4~~3.96%	0%	~~20~~19.84%	2~~6~~5.87%	30.33%	0%	100%
Scheduling Infrastructure (SI)	0%	0%	9~~4~~3.92%	0%	6.08%	0%	100%
Scheduling Infrastructure Business Rules (SIBR)	0%	0%	9~~4~~3.92%	0%	6.08%	0%	100%
Security Constrained Economic Dispatch (SCED)	40%	0%	0%	0%	60%	0%	100%
Security- External/Physical	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Security-ISS (CUDA)	23%	0%	22%	3%	7%	45%	100%
Settlements and Market Clearing	0%	0%	0%	0%	0%	100%	100%
Sign Board (Symon Board maint.)	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Startup Costs through 3/31/98, Working Capital-3 months	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Storage (EMC symmetrix)	1~~9~~8.67%	~~10~~9.55%	1~~4~~3.71%	4.21%	1~~2~~1.77%	42.09%	100%
System Equipment Buyouts (lease buyouts)	43.27%	1.02%	7.34%	~~2~~1.79%	11.03%	3~~6~~5.56%	100%
Telephone/PBX	44.06%	21.47%	~~4~~3.51%	~~4~~3.93%	10.21%	1~~7~~6.81%	100%
Training Systems	23.46%	0.18%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation	100%	0%	0%	0%	0%	0%	100%
Transmission Map Plotting & Display	50%	50%	0%	0%	0%	0%	100%
Trustee Costs, Interest-Capitalized, User Groups	5~~4~~3.60%	~~1~~0.55%	1~~1~~0.62%	1~~6~~5.74%	17.48%	2%	100%

Utilities – System i.e. Print drivers	23.46%	0.18%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
Vitria (Middleware)	23.46%	0.18%	2~~2~~1.78%	~~3~~2.68%	~~7~~6.86%	45.04%	100%
Wide Area Network (WAN)	4~~1~~0.80%	2.14%	1~~9~~8.68%	1.31%	~~8~~7.60%	29.48%	100%
Capital Expenditures for Systems not Specified	32.20%	7.40%	15%	~~6~~5.50%	1~~1~~0.60%	29.30%	100%

Table 3

Reallocation Factors for Projected Unrecovered Portion of Settlements, Metering, and Client Relations Revenue Requirement

	CRS	ETS	FS	CM	MU	SMCR	Total
Functional Association of Settlements, Metering, and Client Relations	0.0%	70.34%	0.0%	8.23%	21.43%	0.0%	100.0%

Part F – Other Modifications to the Rates

Consistent with a Settlement Agreement accepted by the FERC in Docket Nos. ER04-115-000, et al., GMC rates and charges shall be calculated consistent with the following additional requirements during the period that the GMC rates and charges specified in that Settlement Agreement remain in effect:

1. The GMC chargeable to a Scheduling Coordinator for transactions representing transfers from the Mohave generation facility to the Loads of the Mohave co-owners located outside of the ISO Control Area, will be reduced by excluding 65 percent of those

Loads from the Energy Transmission Services Net Energy Charge and the Core Reliability Services – Energy Exports Charge. Such excluded Load shall not be included in the denominators used to calculate the rates for the Energy Transmission Services – Net Energy Charge and the Core Reliability Services – Energy Export Charge.

2. The Forward Scheduling Charge assessed against Schedules submitted by PG&E solely in its role as Path 15 facilitator will be reduced by excluding 65 percent of the number of such Schedules from the Forward Scheduling Charge. Such excluded Schedules shall not be included in the denominator upon which the Forward Scheduling Charge is calculated.

3. Modesto Irrigation District (MID) is a Scheduling Coordinator and also is responsible for a portion of the GMC charges payable by another Scheduling Coordinator, Pacific Gas and Electric Company (PG&E) pursuant to a contract between them. MID and PG&E have agreed that MID shall pay the ISO directly $75,000 each month, in lieu of any payments to PG&E for its share of the GMC charges payable by PG&E and the ISO shall credit a portion of the amount received from MID to PG&E as an offset to PG&E's obligation for GMC charges. Any difference, positive or negative, between the amount credited to PG&E and the amount paid by MID to the ISO under this provision shall be reflected in the Operating and Capital Reserves Account. The payment arrangement described in this paragraph is subject to the conditions, and will be implemented pursuant to the procedures, set forth in the Offer of Partial Settlement accepted by the FERC in Docket Nos. ER04-115-000, et al. This arrangement shall not apply to MID's obligation for GMC charges as a Scheduling Coordinator, which shall be governed by the provisions of this Schedule 1 and the other applicable provisions of the ISO Tariff, except that in the event that MID accepts responsibility for scheduling any load

currently scheduled by PG&E under SCID PGAB, the ISO will not charge any additional GMC at the tariffed GMC rate, but rather will attribute such schedules and load to the fixed $75,000.00 per month payment set forth above, provided that MID schedules such load under a new and separate SCID and the ISO shall not assess GMC charges to such SCID..

* * *

SETTLEMENT AND BILLING PROTOCOL

SABP 3 COMPUTATION OF CHARGES

SABP 3.1 Description of Charges to be Settled

The ISO shall, based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, calculate the following:

(a) the amount due from each Scheduling Coordinator for its share for the relevant month of the ~~seven~~ eight components of the Grid Management Charge in accordance with the formula located in Appendix F, Schedule 1, Part A of this Tariff. These Charges shall accrue on a monthly basis.

(b) the amount due from each Scheduling Coordinator for the Grid Operations Charge in accordance with Appendix F, Schedule 2 of this Tariff. This charge shall accrue on a monthly basis.

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

(d) the amount due from and/or owed to each Scheduling Coordinator for Imbalance Energy in accordance with Appendix D, for each of the Settlement Periods of Day 0.

(e) the amount due from and/or owed to each Scheduling Coordinator for Usage Charges in accordance with Appendix E, for each of the Settlement Periods of Day 0.

(f) the amount due from each Scheduling Coordinator for Wheeling Out and Wheeling Through Charges and the amount owed to each Participating TO for these charges in accordance with Appendix F, for each of the Settlement Periods of Day 0.

(g) the amounts due from/to Scheduling Coordinators for Voltage Support (supplemental reactive power charges) for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(h) the monthly charges due from/to Scheduling Coordinators for long-term Voltage Support provided by Owners of Reliability Must-Run Units in accordance with Appendix G.

(i) the amounts due from/to Scheduling Coordinators for the provision of Black Start Energy from Reliability Must-Run Units for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(j) the amounts due from/to Black Start Generators for the provision of Black Start Energy for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(k) the amount due from each UDC or MSS, or from a Scheduling Coordinator delivering Energy for the supply of Gross Load not directly connected to the facilities of a UDC or MSS, for the High Voltage Access Charge and Transition Charge in accordance with operating procedures posted on the ISO Home Page. These charges shall accrue on a monthly basis.

(l) the amounts due from Scheduling Coordinators for FERC Annual Charges.

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.5 of the ISO Tariff.

The ISO shall calculate these amounts using the software referred to in SABP 2.1 except in cases of system breakdown when it shall apply the procedures set out in SABP 9 (Emergency Procedures).

SABP 3.1.1 Additional Charges and Payments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

(b) amounts in respect of penalties which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty; and

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day.

(d) amounts required with respect to payment adjustments for regulating Energy as calculated in accordance with Section 2.5.27.1 of the ISO Tariff. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh for that Trading Day.

SABP 3.2 Method of Settlement of Charges

SABP 3.2.1 Settlement of Payments to/from Scheduling Coordinators and Participating TOs

The ISO will calculate for each charge the amounts payable by the relevant Scheduling Coordinator, Black Start Generator or Participating TO for each Settlement Period of the Trading Day, and the amounts payable to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for each Settlement Period of that Trading Day and shall arrive at a net amount payable for each charge by or to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for that Trading Day. Each of these amounts will appear in the Preliminary and Final Settlement Statements that the ISO will provide to the relevant Scheduling Coordinator, Black Start Generator or Participating TO as provided in SABP 4.

The ~~seven~~eight components of the Grid Management Charge will be included in the Preliminary Settlement Statement and Final Settlement Statement with the other types of charges referred to in SABP 3.1, but a separate invoice for the Grid Management Charge, stating the rate, billing determinant volume, and total charge for each of its ~~seven~~ eight components, will be issued by the ISO to the Scheduling Coordinator.

* * *

SABP 5 INVOICES

The ISO shall provide on the day specified in the ISO Payments Calendar an invoice in the format set out in SABP Appendix I showing:

(a) amounts which according to each of the Preliminary and Final Settlement Statements of that Billing Period are to be paid from or to each Scheduling Coordinator, Black Start Generator or Participating TO;

(b) the Payment Date, being the date on which such amounts are to be paid or received and the time for such payment; and

(c) details (including the account number, bank name and Fed-Wire transfer instructions) of the ISO Clearing Account to which any amounts owed by the Scheduling Coordinator, Black Start Generator or Participating TO are to be paid.

A separate invoice for the Grid Management Charge, stating the rate, billing determinant volume and total charge for each of its ~~seven~~ eight components, will be issued by the ISO to the Scheduling Coordinator.

A separate invoice for Interest, issued on the preliminary invoice date, stating the total charges for each Trade Month in which interest is charged, will be issued by the ISO.

SABP 6 PAYMENT PROCEDURES

SABP 6.1 Time of Payment

SABP 6.1.1 Payment Date

Subject to SABP 6.1.2, payment will be made by the ISO and by each Scheduling Coordinator, Black Start Generator and Participating TO on the Payment Date as set forth in Section 11.3.2. Payment will be made by the ISO in accordance with Section 11.13.

SABP 6.1.2 Prepayments

(a) A Scheduling Coordinator may choose to pay at an earlier date than the Payment Date specified in the ISO Payments Calendar by way of prepayment provided it notifies the ISO by electronic means before submitting its prepayment.

(b) Prepayment notifications must specify the dollar amount prepaid.

(c) Prepayments must be made by Scheduling Coordinators via Fed-Wire into their ISO prepayment account designated by the ISO. The relevant Scheduling Coordinator shall grant the ISO a security interest on all funds in its ISO prepayment account.

(d) On any Payment Date the ISO shall be entitled to cause funds from the relevant Scheduling Coordinator's ISO prepayment account to be transferred to the ISO Clearing Account in such amounts as may be necessary to discharge in full that Scheduling Coordinator's payment obligation arising in relation to that Payment Date.

(e) Any funds held in the relevant Scheduling Coordinator's ISO prepayment account shall be treated as part of that Scheduling Coordinator's Security.

(f) Interest (or other income) accruing on the relevant Scheduling Coordinator's ISO prepayment account shall inure to the benefit of that Scheduling Coordinator and shall be added to the balance of its ISO prepayment account on a monthly basis.

(g) Funds held in an ISO prepayment account by a Scheduling Coordinator may be recouped, offset or applied by the ISO to any outstanding financial obligations of that Scheduling Coordinator to the ISO or to other Scheduling Coordinators under this Protocol.

SABP 6.2 Payments to be made by Fed-Wire

All payments by the ISO to Scheduling Coordinators, Black Start Generators and Participating TOs shall be made by Fed-Wire.

All payments to the ISO by Scheduling Coordinators, Black Start Generators and Participating TOs shall be made by Fed-Wire.

SABP 6.3 Payment Process

SABP 6.3.1 Use of the ISO Clearing Account

(a) Subject to SABP 6.1.2 each ISO Debtor shall remit to the ISO Clearing Account the amount shown on the invoice as payable by that ISO Debtor for value not later than 10:00 am on the Payment Date.

(b) On the Payment Date the ISO shall be entitled to cause the transfer of such amounts held in a Scheduling Coordinator's ISO prepayment account to the ISO Clearing Account as provided in SABP 6.1.2(c).

SABP 6.3.1.2 Distribution to ISO Creditors

The ISO shall calculate the amounts available for distribution to ISO Creditors on the Payment Date specified in Section 11.13 and shall give irrevocable instructions to the ISO Bank to remit from the ISO Clearing Account to the relevant Settlement Account maintained by each ISO Creditor for same day value the amounts determined by the ISO to be available for payment to each ISO Creditor. If required, the ISO shall instruct the ISO Bank to transfer amounts from the ISO Reserve Account to enable the ISO Clearing Account to clear by the close of banking business on the Payment Date.

SABP 6.3.1.3 Grid Management Charge

The ISO is authorized to instruct the ISO Bank to debit the ISO Clearing Account and transfer to the relevant ISO account sufficient funds to pay in full the Grid Management Charge falling due on any Payment Day with priority over any other payments to be made on that or on subsequent days out of the ISO Clearing Account.

SABP 6.4 **Use of the ISO Reserve Account**

If there are insufficient funds in the ISO Clearing Account to pay ISO Creditors and clear the account on any Payment Date, due to payment default by one or more ISO Debtors, the ISO shall transfer funds from the ISO Reserve Account to the ISO Clearing Account to clear it by close of banking business on that Payment Date pursuant to SABP 6.7.2.

SABP 6.5 **Use of the ISO Surplus Account**

SABP 6.5.1 **Establishment**

The ISO shall establish and maintain a bank account in accordance with this Protocol denominated the "ISO Surplus Account".

SABP 6.5.2 **Other Funds Used in the ISO Surplus Account.**

(a) Any amounts paid to the ISO in respect of penalties referred to in SABP 3.1.1 shall be credited to the Surplus Account.

(b) The funds referred to in SABP 6.5.2(a) pertaining to Penalties as provided in SABP 3.1.1 shall first be applied towards any expenses, loss or costs incurred by the ISO. Any excess will be credited to the Surplus Account pursuant to SABP 6.5.2(a).

(c) The funds referred to in SABP 6.5.2(a) pertaining to default Interest referred to in SABP 6.10.5 shall first be applied towards any unpaid creditor balances for the trade month in which the default Interest was assessed and second to any other unpaid creditor balances. Only after all unpaid creditor balances are satisfied in full will any excess funds pertaining to default Interest be credited to the Surplus Account pursuant to SABP 6.5.2(a).

SABP 6.5.3 **Distribution of Funds**

In the event that there are funds in the ISO Surplus Account in excess of an amount to be determined by the ISO Governing Board and noticed by the ISO to Market Participants, the amount of such excess will be distributed to Scheduling Coordinators using the same method of apportioning the refund as the method employed in apportioning the liability for the Grid Management Charge.

SABP 6.5.4 **Trust**

All amounts standing to the credit of the ISO Surplus Account will be held at all times on trust for Market Participants in accordance with this Protocol.

Attachment B
Part 2

Blacklined Revised ISO Tariff Sheet Presuming Commission Approval of ISO Tariff Amendment 54 Prior to Approval of Offer of Partial Settlement

Energy Export	For purposes of calculating the Grid Management Charge, Energy included in an interchange Schedule submitted to the ISO, or dispatched by the ISO, to serve a Load located outside the ISO's Control Area, whether the Energy is produced by a Generator in the ISO Control Area or a resource located outside the ISO's Control Area.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.
Ex Post Price	The Hourly Ex Post Price, the Dispatch Interval Ex Post Price, the Resource-Specific Settlement Interval Ex Post Price, or the Zonal Settlement Interval Ex Post Price.
Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.

Attachment C

GMC Rates for 2004

GMC Charges for 2004

CRS Peak	$106.8332 per MW
CRS Off-Peak	$70.5098 per MW
CRS Energy Exports	$0.4277 per MWh
ETS-NE	$0.3379 per MWh
ETS-UE	$0.7123 per MWh
FS	$1.1785 per schedule
FS – Inter SC Trades	$0.5893 per schedule
CONG	$0.2043 per MWh
MU	$0.8034 per MWh
SMCR	$500 per Scheduling Coordinator per month

Attachment D

Revised PG&E Pass Through Tariff Sheets

PACIFIC GAS AND ELECTRIC COMPANY

GMC PASS-THROUGH TARIFF
2004

GMC PASS-THROUGH TARIFF
Table of Contents

I. BACKGROUND, DEFINITIONS AND SCOPE

1. Background.

The purpose of this GMC Pass-Through Tariff is to provide a mechanism for recovery of certain of the ISO's GMC charges to Pacific Gas and Electric Company ("PG&E"), by passing through those charges individually to each respective CAA Customer as defined herein. The ISO imposes GMC charges on PG&E as a Scheduling Coordinator ("SC"), under RPTO Agreements and the ISO Tariff. This Tariff sets forth the terms and conditions under which PG&E will pass-through certain of the ISO's GMC costs billed to PG&E.

These ISO GMC costs include: (1) Core Reliability Services Demand Charge, (2) Core Reliability Services Energy Exports Charge, (3) Energy Transmission Services Net Energy Charge, (4) Energy Transmission Services Uninstructed Deviations Charge, (5) Forward Scheduling Charge, (6) Market Usage Charge, and (7) Settlements, Metering and Client Relations Charge, as those terms are detailed in the GMC provisions of the ISO Tariff filing in Docket No. ER04-115-000 on October 31, 2003 and as revised by the Offer of Settlement filed by the ISO and PG&E in Docket Nos. ER04-115-000 and ER04-242-000 on July 29, 2004.

2. Definitions and Interpretation.

2.1. Master Definitions Supplement. Unless defined in Section 2.2 of this Tariff, all terms and expressions used in this Tariff shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

2.2. Special Definitions. The following terms used in this Tariff are defined as set out below:

"**Commission**" means the Federal Energy Regulatory Commission.

"**Control Area Agreements**" ("CAA") means the existing wholesale contracts listed in Appendix A, entered into prior to commencement of ISO operations, under which PG&E provides certain ancillary services and other control area services.

"**CAA Customers"** means the customers listed in Appendix A of this Tariff, who are parties to the Control Area Agreements.

"**Effective Date**" means January 1, 2004, or any other date that the Commission permits this GMC Pass-Through Tariff to become effective. It is intended that this effective date be the same date that the Commission permits the ISO's unbundled GMC filing in Docket No. ER04-115-000, to be effective.

"**Party**" means PG&E and any CAA Customer.

"**Responsible Participating Transmission Owner Agreement ("RPTO Agreement")**" means the agreement entitled "Responsible Participating Transmission Owner Agreement" between PG&E and the ISO dated December 10, 1997, as filed in Docket No. ER98-1057-000, as amended from time to time.

2.3. Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Tariff:

(a) If there are any inconsistencies between this Tariff and any other tariff or agreement to which PG&E and any CAA Customer listed in Appendix A are parties, this Tariff will prevail to the extent of the inconsistency;

(b) If there are any inconsistencies between this Tariff and the ISO Tariff or the TO Tariff, this Tariff will prevail to the extent of the inconsistency except as expressly provided otherwise in this Tariff;

(c) the singular shall include the plural and vice versa;

(d) "includes" or "including" shall mean "including without limitation";

(e) references to a Section, Article or Appendix shall mean a Section, an Article or an Appendix of this

Tariff, as the case may be, unless the context otherwise requires;

(f) a reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made;

(g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;

(h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;

(i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;

(j) any reference to a day, week, month or year is to a calendar day, week, month or year; and

(k) the captions and headings in this Tariff are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Tariff.

3. Scope.

3.1. Pass-through of ISO GMC Costs. This Tariff provides for the pass-through of GMC costs incurred by PG&E on behalf of CAA Customers. PG&E will levy the pass-through, which is described in Section 4 and Schedule 1 of this Tariff, monthly on each CAA Customer beginning on the Effective Date.

3.2. Customers under the Tariff. This Tariff is mandatory for all CAA Customers. No other entities may take service under this Tariff.

II. CHARGES, BILLING AND PAYMENT

4. Charges Under GMC Pass-Through Tariff.

Under this GMC Pass-Through Tariff, PG&E shall collect, and the CAA Customers shall pay, the GMC PG&E incurs as SC on behalf of CAA Customers listed in Appendix A. The GMC Pass-through amount is determined under the principles described in Sections 4.1 through 4.3, and Schedule 1 of this Tariff.

4.1. Pass-through of Costs Actually Incurred. The GMC Pass-through amount shall be a monthly charge on CAA Customers, that reflects the actual GMC costs and payment obligations incurred by PG&E. In the event that the allocation described in Section 4.2 of this Tariff results in a pass-through amount that is greater than PG&E's actual GMC costs, PG&E will perform a true-up to ensure that an over-recovery does not occur.

4.2. Allocation on the Same Basis as Allocated to PG&E. The allocation formula for each of the ISO charge types is shown in the GMC provisions of the ISO Tariff filing in Docket No. ER04-115-000 and therein specifically in Section 8.3 of the proposed ISO Tariff. The allocation of the GMC to CAA Customers is shown on Schedule 1 to this Tariff, and shall, as much as practicable, be made on the same basis as the ISO allocates those costs to PG&E.

4.3. Changes to GMC Pass-Through Tariff. PG&E reserves the right to file unilateral amendments under Section 205 of the Federal Power Act to the GMC Pass-Through Tariff as necessary.

5. Amendment to Control Area Agreements.

To the extent necessary to allow PG&E to collect the ISO GMC Pass-Through Tariff costs from CAA Customers under this Tariff, this Tariff shall constitute an amendment to each CAA in order to allow PG&E to collect the GMC Pass-through, commencing on the Effective Date of this Tariff.

6. Billing and Payments.

6.1. Billing and Payment. PG&E as Participating Transmission Owner (PTO) shall submit an invoice to the CAA Customers on or after the last day of each billing period. Full payment of invoice shall be due upon delivery and must be received by PG&E no later than twenty (20) calendar days from the date of the invoice. All payments shall be made in immediately available funds payable to PG&E or by wire transfer to a bank named by PG&E.

6.2. Interest on Unpaid Balances. Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. Section 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the date of the invoice to the date of payments. When payments are made by mail, invoices shall be considered as having been paid on the date of receipt by PG&E.

6.3. Billing Disputes. All payments shall be made in full without offset or reduction regardless of the existence of any dispute. A dispute between either PG&E and a CAA Customer, or PG&E and any Third Party, or a CAA

Customer and any Third Party shall not be a proper basis for contesting an invoice under this agreement.

6.4. Customer Default. Nonpayment of all or any part of a disputed invoice on or before the due date as described above, and in the event such failure of payment is not corrected within 30 calendar days after PG&E notifies the CAA Customer, to cure such failure, a default by the CAA Customer shall be deemed to exist. Upon the occurrence of a default, PG&E may initiate a proceeding with the Commission (or the Local Regulatory Authority for a Local Publicly Owned Electric Utility).

III. GENERAL PROVISIONS

7. Regulatory Filings.

Nothing contained in this Tariff shall be construed as affecting in any way the right of PG&E to make unilateral application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder. Nothing contained in this Tariff shall be construed as affecting in any way the ability of any CAA Customer or other appropriate party to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

8. No Expansion of Obligations.

Nothing in this Tariff is intended to expand PG&E's obligations under the RPTO Agreement or the CAA nor to create new duties or obligations for PG&E. In addition, this Tariff is not intended to expand, or change in any way, scheduling protocols under CAA. This Tariff is explicitly not available to any new customer, or to any expansion of service to an existing CAA Customer.

9. Force Majeure and Indemnification.

9.1. Force Majeure. An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither PG&E nor the CAA Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

9.2. Indemnification. PG&E and the CAA Customer shall at all times indemnify, defend, and save each other harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other party's performance of its obligations under this Tariff, except in cases of negligence or intentional wrongdoing by the other party.

10. Creditworthiness.

Except as provided in Section 15 of this Tariff, for the purpose of determining the ability of the CAA Customer to meet its obligations under this Tariff, PG&E may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, PG&E, after a demonstration of good cause, may require the CAA Customer to provide and maintain in effect an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the CAA Customer and acceptable to PG&E and consistent with commercial practices established by the Uniform Commercial Code that protects PG&E against the risk of non-payment.

11. Dispute Resolution Procedures.

11.1. ISO ADR Procedures. As limited to the disputing parties, the ISO ADR Procedures set forth in the currently-effective Section 13 of the ISO Tariff shall apply to all disputes under this Tariff, except that those procedures shall not apply to disputes as to whether rates and charges covered by this Tariff are just and reasonable under the Federal Power Act. For CAA Customer disputes that concern the ISO’s assessment of GMC to PG&E, the time limits for raising disputes under Sections 11.7.2 and 11.7.3 of the ISO Tariff shall apply, provided that PG&E has provided the CAA customers with copies of the Preliminary Settlement Statement and Final Settlement Statement within two business days after receiving such Settlement Statements from the ISO. The time limits for raising disputes that concern PG&E’s allocation and billing of GMC to CAA Customers shall be twelve months from the date when PG&E issues the invoice.

11.2. Rights under the Federal Power Act. Nothing in this Section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

12. Waiver.

Any waiver at any time by any Party of its rights with respect to any default under this Tariff, or with respect to any other matter arising in connection with this Tariff, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Tariff. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

13. Preservation of Obligations.

Upon termination of this Tariff, all unsatisfied obligations of each Party shall be preserved until satisfied.

14. Governing Law.

Except as provided in Section 15 of this Tariff, this Tariff shall be interpreted, governed by, and construed under the laws of the State of California, without regard to the principles of conflict of laws thereof, or the laws of the United States, as applicable, as if executed and to be performed wholly within the State of California.

15. Consistency with Federal Laws and Regulations.

15.1. Nothing in this Tariff shall compel any person or federal entity to: (1) violate federal statutes or regulations; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statues, regulations, or orders lawfully promulgated thereunder. If any provision of this Tariff is inconsistent with any obligation imposed on any person or federal entity by federal law or regulation to that extent, it shall be inapplicable to that person or federal entity. No person or federal entity shall incur any liability by failing to comply with a Tariff provision that is inapplicable to it by reason of being inconsistent with any federal statutes, regulations, or orders lawfully promulgated thereunder; provided, however, that such person or federal entity shall use its best efforts to comply with this Tariff to the extent that applicable federal laws, regulations, and orders lawfully promulgated thereunder permit it to do so.

15.2. If any provision of this Tariff requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, PG&E shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Tariff that are not enforceable against the federal entity.

16. Appendices and Schedules Incorporated.

The Appendices and Schedules to this Tariff, as may be revised from time to time, are attached to this Tariff and are incorporated by reference as if fully set forth herein.

17. Effective Date.

The Effective Date of this Tariff shall be January 1, 2004, or whatever date the Commission accepts and makes effective the ISO's filing in Docket No. ER04-115-000.

Appendix A

CONTROL AREA AGREEMENT CUSTOMERS

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Control Area Agreement (CAA) Customers

CAA CUSTOMERS	CONTROL AREA AGREEMENTS
Bay Area Rapid Transit District	Service Agreement No. 42 under FERC Electric Tariff, First Revised Volume No. 3 (OAT)
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Schedule 1

PG&E'S
GMC PASS-THROUGH TARIFF

PG&E's
GMC Pass-Through Tariff
Schedule 1

This Schedule 1 is designed to be consistent with Schedule 1 of the ISO filings in Docket No. ER04-115-000 filed on October 31, 2003 as revised by the Offer of Settlement filed by the ISO and PG&E in Docket Nos. ER04-115-000 and ER04-242-000 on July 29, 2004, and as may be subsequently revised. Calculation of the Monthly GMC Pass-Through Tariff billing components for Control Area Agreement (CAA) Customers is based upon the following service charges included in the ISO's GMC that are applicable to the CAA Customer and the relevant SC Portfolio (i.e., the SC Portfolio that includes the CAA Customer):

(1) The Core Reliability Services Demand Charge for each CAA Customer is calculated as the product of the ISO rate, on-peak or off peak, as charged to the SC Portfolio, for the Core Reliability Services Demand Charge and the CAA Customer's share of the relevant SC Portfolio's Demand that is not associated with Energy Exports, calculated using the SC Portfolio's metered non-coincident peak hourly Demand during the month (in megawatts) less the volume of Energy Exports included in the SC Portfolio's non-coincident peak hourly Demand for the month, as determined by the ISO. A Customer's metered non-coincident peak hourly Demand during

the month is determined as if that Customer were a stand-alone entity being charged GMC under the ISO's proposed 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Core Reliability Services Demand Charge billing quantity calculated by the ISO. This share is the Customer's billing quantity for purposes of allocating the Core Reliability Services Demand Charge.

(2) The Core Reliability Services Energy Exports Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's Energy Exports calculated using the SC Portfolio's metered volume of Energy Exports (in megawatt-hours), as determined by the ISO for the SC Portfolio. Each CAA Customer's Energy Exports are calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the portfolio's Core Reliability Services Energy Exports billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Core Reliability Services Energy Exports Charge.

(3) The Energy Transmission Services Net Energy Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's Metered Control Area Load (in megawatt-hours), as determined by the ISO for the SC Portfolio. Each CAA Customer's Metered Control Area Load is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Energy Transmission Services Net Energy Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Energy Transmission Services Net Energy Charge.

(4) The Energy Transmission Services Uninstructed Deviations Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's net uninstructed deviations by Settlement Interval, as determined by the ISO for the SC Portfolio. Each CAA Customer's uninstructed deviations is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Energy

Transmission Services Uninstructed Deviations Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Energy Transmission Services Net Energy Charge.

(5) The Forward Scheduling Charge for each CAA Customer is calculated as the product of the ISO rate, as applicable to different schedule types, and the CAA Customer's share of the relevant SC Portfolio's sum of Final Hour-Ahead Schedules, including all awarded Ancillary Services bids, with a value other than 0 MW, submitted to the scheduling infrastructure/scheduling application system, as determined by the ISO for the SC Portfolio. Each CAA Customer's sum of Final Hour-Ahead Schedules is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Forward Scheduling Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Forward Scheduling Charge.

(6) The Market Usage Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's absolute

value of market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval), as determined by the ISO for the SC Portfolio. Each CAA Customer's absolute value of market purchases and sales is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Market Usage Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Market Usage Charge.

(7) The Settlements, Metering and Client Relations Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the GMC charges for the relevant SC Portfolio. The sum of the CAA Customer-specific GMC charges determines that Customer's pro-rata share of the SC Portfolio's Settlements, Metering, and Client Relations Charge calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Settlements, Metering, and Client Relations Charge.

Attachment E

Blacklined Revised
PG&E Pass Through Tariff Sheets

PACIFIC GAS AND ELECTRIC COMPANY

GMC PASS-THROUGH TARIFF
2004
~~Exhibit PGE-1~~

GMC PASS-THROUGH TARIFF
Table of Contents

I. BACKGROUND, DEFINITIONS AND SCOPE

1. Background.

The purpose of this GMC Pass-Through Tariff is to provide a mechanism for recovery of certain of the ISO's GMC charges to Pacific Gas and Electric Company ("PG&E"), by passing through those charges individually to each respective CAA Customer as defined herein. The ISO imposes GMC charges on PG&E as a Scheduling Coordinator ("SC"), under RPTO Agreements and the ISO Tariff. This Tariff sets forth the terms and conditions under which PG&E will pass-through certain of the ISO's GMC costs billed to PG&E.

These ISO GMC costs include: (1) Core Reliability Services Demand Charge, (2) Core Reliability Services Energy Exports Charge, (3) Energy ~~and~~ Transmission Services Net Energy Charge, (4) Energy Transmission Services Uninstructed Deviations Charge, (5~~3~~) Forward Scheduling Charge, (6~~4~~) Market Usage Charge~~and Services~~, and (7~~5~~) Settlements, Metering and Client Relations Charge, as those terms are detailed in the GMC provisions of the ISO Tariff filing in Docket No. ER04-115-000 on October 31, 2003 and as revised by the Offer of Settlement filed by the ISO and PG&E in Docket Nos. ER04-115-000 and ER04-242-000 on July 29, 2004.

2. Definitions and Interpretation.

2.1. Master Definitions Supplement. Unless defined in Section 2.2 of this Tariff, all terms and expressions used in this Tariff shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

2.2. Special Definitions. The following terms used in this Tariff are defined as set out below:

"**Commission**" means the Federal Energy Regulatory Commission.

"**Control Area Agreements**" ("CAA") means the existing wholesale contracts listed in Appendix A, entered into prior to commencement of ISO operations, under which PG&E provides certain ancillary services and other control area services.

"**CAA Customers**" means the customers listed in Appendix A of this Tariff, who are parties to the Control Area Agreements.

"**Effective Date**" means January 1, 2004, or any other date that the Commission permits this GMC Pass-Through Tariff to become effective. It is intended that this effective date be the same date that the Commission permits the ISO's unbundled GMC filing in Docket No. ER04-115-000, to be effective.

"**Party**" means PG&E and any CAA Customer.

"**Responsible Participating Transmission Owner Agreement ("RPTO Agreement")**" means the agreement entitled "Responsible Participating Transmission Owner Agreement" between PG&E and the ISO dated December 10, 1997, as filed in Docket No. ER98-1057-000, as amended from time to time.

2.3. Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Tariff:

(a) If there are any inconsistencies between this Tariff and any other tariff or agreement to which PG&E and any CAA Customer listed in Appendix A are parties, this Tariff will prevail to the extent of the inconsistency;

(b) If there are any inconsistencies between this Tariff and the ISO Tariff or the TO Tariff, this Tariff will prevail to the extent of the inconsistency except as expressly provided otherwise in this Tariff;

(c) the singular shall include the plural and vice versa;

(d) "includes" or "including" shall mean "including without limitation";

(e) references to a Section, Article or Appendix shall mean a Section, an Article or an Appendix of this

Tariff, as the case may be, unless the context otherwise requires;

(f) a reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made;

(g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;

(h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;

(i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;

(j) any reference to a day, week, month or year is to a calendar day, week, month or year; and

(k) the captions and headings in this Tariff are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Tariff.

3. Scope.

3.1. Pass-through of ISO GMC Costs. This Tariff provides for the pass-through of GMC costs incurred by PG&E on behalf of CAA Customers. PG&E will levy the pass-through, which is described in Section 4 and Schedule 1 of this Tariff, monthly on each CAA Customer beginning on the Effective Date.

3.2. Customers under the Tariff. This Tariff is mandatory for all CAA Customers. No other entities may take service under this Tariff.

II. CHARGES, BILLING AND PAYMENT

4. Charges Under GMC Pass-Through Tariff.

Under this GMC Pass-Through Tariff, PG&E shall collect, and the CAA Customers shall pay,~~recover~~ the GMC PG&E~~it~~ incurs as SC on behalf of CAA Customers listed in Appendix A. The GMC Pass-through amount is determined under the principles described in Sections 4.1 through 4.3, and Schedule 1 of this Tariff.

4.1. Pass-through of Costs Actually Incurred. The GMC Pass-through amount shall be a monthly charge on CAA Customers, that reflects the actual GMC costs and payment obligations incurred by PG&E. In the event that the allocation described in Section 4.2 of this Tariff results in a pass-through amount that is greater than PG&E's actual GMC costs, PG&E will perform a true-up to ensure that an over-recovery does not occur.

4.2. Allocation on the Same Basis as Allocated to PG&E. The allocation formula for each of the ISO charge types is shown in the GMC provisions of the ISO Tariff filing in Docket No. ER04-115-000 and therein specifically in Section 8.3 of the proposed ISO Tariff. The allocation of the GMC to CAA Customers is shown on Schedule 1 to this Tariff, and shall, as much as practicable, be made on the same basis as the ISO allocates those costs to PG&E.

4.3. Changes to GMC Pass-Through Tariff. PG&E reserves the right to file unilateral amendments under Section 205 of the Federal Power Act to the GMC Pass-Through Tariff as necessary.

5. Amendment to Control Area Agreements.

To the extent necessary to allow PG&E to collect the ISO GMC Pass-Through Tariff costs from CAA Customers under this Tariff, this Tariff shall constitute an amendment to each CAA in order to allow PG&E to collect the GMC Pass-through, commencing on the Effective Date of this Tariff.

6. Billing and Payments.

6.1. Billing and Payment. PG&E as Participating Transmission Owner (PTO) shall submit an invoice to the CAA Customers on or after the last day of each billing period. Full payment of invoice shall be due upon delivery and must be received by PG&E no later than twenty (20) calendar days from the date of the invoice. All payments shall be made in immediately available funds payable to PG&E or by wire transfer to a bank named by PG&E.

6.2. Interest on Unpaid Balances. Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. Section 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the date of the invoice to the date of payments. When payments are made by mail, invoices shall be considered as having been paid on the date of receipt by PG&E.

6.3. Billing Disputes. All payments shall be made in full without offset or reduction regardless of the existence of any dispute. A dispute between either PG&E and a CAA Customer, or PG&E and any Third Party, or a CAA

Customer and any Third Party shall not be a proper basis for contesting an invoice under this agreement.

6.4. Customer Default. Nonpayment of all or any part of a disputed invoice on or before the due date as described above, and in the event such failure of payment is not corrected within 30 calendar days after PG&E notifies the CAA Customer, to cure such failure, a default by the CAA Customer shall be deemed to exist. Upon the occurrence of a default, PG&E may initiate a proceeding with the Commission (or the Local Regulatory Authority for a Local Publicly Owned Electric Utility).

III. GENERAL PROVISIONS

7. Regulatory Filings.

Nothing contained in this Tariff shall be construed as affecting in any way the right of PG&E to make unilateral application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder. Nothing contained in this Tariff shall be construed as affecting in any way the ability of any CAA Customer or other appropriate party to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

8. No Expansion of Obligations.

Nothing in this Tariff is intended to expand PG&E's obligations under the RPTO Agreement or the CAA nor to create new duties or obligations for PG&E. In addition, this Tariff is not intended to expand, or change in any way, scheduling protocols under CAA. This Tariff is explicitly not available to any new customer, or to any expansion of service to an existing CAA Customer.

9. Force Majeure and Indemnification.

9.1. Force Majeure. An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither PG&E nor the CAA Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

9.2. Indemnification. PG&E and the CAA Customer shall at all times indemnify, defend, and save each other harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other party's performance of its obligations under this Tariff, except in cases of negligence or intentional wrongdoing by the other party.

10. Creditworthiness.

Except as provided in Section 15 of this Tariff, for the purpose of determining the ability of the CAA Customer to meet its obligations under this Tariff, PG&E may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, PG&E, after a demonstration of good cause, may require the CAA Customer to provide and maintain in effect an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the CAA Customer and acceptable to PG&E and consistent with commercial practices established by the Uniform Commercial Code that protects PG&E against the risk of non-payment.

11. Dispute Resolution Procedures.

11.1. ISO ADR Procedures. As limited to the disputing parties, the ISO ADR Procedures set forth in the currently-effective Section 13 of the ISO Tariff shall apply to all disputes under this Tariff, except that those procedures shall not apply to disputes as to whether rates and charges covered by~~set forth in~~ this Tariff are just and reasonable under the Federal Power Act. For CAA Customer disputes that concern the ISO's assessment of GMC to PG&E, the time limits for raising disputes under Sections 11.7.2 and 11.7.3 of the ISO Tariff shall apply, provided that PG&E has provided the CAA customers with copies of the Preliminary Settlement Statement and Final Settlement Statement within two business days after receiving such Settlement Statements from the ISO. The time limits for raising disputes that concern PG&E's allocation and billing of GMC to CAA Customers shall be twelve months from the date when PG&E issues the invoice.

11.2. Rights under the Federal Power Act. Nothing in this Section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

12. Waiver.

Any waiver at any time by any Party of its rights with respect to any default under this Tariff, or with respect to any other matter arising in connection with this Tariff, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Tariff. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

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15.2. If any provision of this Tariff requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, PG&E shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Tariff that are not enforceable against the federal entity.

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(1) The Core Reliability Services Demand Charge for each CAA Customer is calculated as the product of the ISO rate, on-peak or off peak, as charged to the SC Portfolio,~~ (shown below)~~ for the Core Reliability Services Demand Charge and the CAA Customer's share of the relevant SC Portfolio's Demand that is not associated with Energy Exports, calculated using the SC Portfolio's metered non-coincident peak hourly ~~d~~Demand during the month (in megawatts) less the volume of Energy Exports included in the SC Portfolio's non-coincident peak hourly Demand for the month, as determined by the ISO. ~~for the SC Pportfolio~~

~~that includes the CAA Customer.~~A Customer's metered non-coincident peak hourly Demand during the month is determined as if that Customer were a stand-alone entity being charged GMC under the ISO's proposed 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Core Reliability Services Demand Charge billing quantity calculated by the ISO. This share is the Customer's billing quantity for purposes of allocating the Core Reliability Services Demand Charge.

(2) The Core Reliability Services Energy Exports Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's Energy Exports calculated using the SC Portfolio's metered volume of Energy Exports (in megawatt-hours), as determined by the ISO for the SC Portfolio. Each CAA Customer's Energy Exports are calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the portfolio's Core Reliability Services Energy Exports billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Core Reliability Services Energy Exports Charge.

(3) The Energy ~~and~~ Transmission Services Net Energy Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's Metered Control Area Load (in megawatt-hours), as determined by the ISO for the SC Portfolio. Each CAA Customer's Metered Control Area Load is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Energy Transmission Services Net Energy Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Energy Transmission Services Net Energy Charge.

(4) The Energy Transmission Services Uninstructed Deviations Charge for each CAA Customer is calculated as the product of the ISO rate and the CAA Customer's share of the relevant SC Portfolio's net uninstructed deviations by Settlement Interval, as determined by the ISO for the SC Portfolio. Each CAA Customer's uninstructed deviations is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Energy

Transmission Services Uninstructed Deviations Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Energy Transmission Services Net Energy Charge.

~~composed of two parts. The first part is calculated as the product of the rate (shown below) for the Energy and Transmission Services Net Energy Charge and the CAA Customer's Metered Control Area Load (in megawatt hours). The second part is calculated as the product of the rate (shown below) for the Energy and Transmission Services Uninstructed Deviations Charge and the CAA Customer's share of the net uninstructed deviations (in megawatt hours) by settlement interval, as determined by the ISO for the SC portfolio that includes the CAA Customer.~~

(5~~3~~) The Forward Scheduling Charge for each CAA Customer is calculated as the product of the ISO rate, as applicable to different schedule types, ~~(shown below)~~ and the CAA Customer's share of the relevant SC Portfolio's sum of Final Hour-Ahead Schedules, including all awarded Ancillary Services bids, with a value other than 0 MW, submitted to the scheduling infrastructure/scheduling application system, as determined by the ISO for the SC Portfolio. Each CAA Customer's sum of Final Hour-Ahead

Schedules is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Forward Scheduling Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Forward Scheduling Charge.

~~for the Forward Scheduling Charge and the CAA Customer's share of the Final, Hour-Ahead Schedule templates, as determined by the ISO for the SC portfolio that includes the CAA Customer.~~

(6~~4~~) The Market Usage ~~and Services~~ Charge for each CAA Customer is calculated as the product of the ISO rate ~~(shown below)~~ and the CAA Customer's share of the relevant SC Portfolio's absolute value of market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval), as determined by the ISO for the SC Portfolio. Each CAA Customer's absolute value of market purchases and sales is calculated as if that Customer were a stand-alone entity being charged GMC under the ISO's 2004 GMC charge methodology. The CAA Customer-specific value determines that Customer's pro-rata share of the SC Portfolio's Market Usage Charge billing quantity calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Market Usage Charge.

~~for the Market Usage and Services Charge and the CAA Customer's share of market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy and net Uninstructed Imbalance Energy, as determined by the ISO for the SC portfolio that includes the CAA Customer.~~

(7~~5~~) The Settlements, Metering and Client Relations Charge for each CAA Customer is calculated as the product of the ISO rate ~~(shown below)~~ and the CAA Customer's share of the GMC charges for the relevant SC Portfolio. The sum of the CAA Customer-specific GMC charges determines that Customer's pro-rata share of the SC Portfolio's Settlements, Metering, and Client Relations Charge calculated by the ISO. This share is the CAA Customer's billing quantity for purposes of allocating the Settlements, Metering, and Client Relations Charge. ~~for the Settlements, Metering and Client Relations Charge and each CAA Customer's fractional share of the GMC charges for items 1 through 4 above for the SC portfolio that includes the CAA Customer.~~

~~GMC Pass-Through Tariff Rates~~

~~Charge~~	~~Rate~~
~~(1) Core Reliability Services~~	~~$160.446/MW~~
~~(2) Energy and Transmission Services, Net Energy~~	~~$.210/MWh(Metered Load)~~
~~Energy and Transmission Services, Uninstructed Deviations~~	~~$.696/MWh(Net Uninstructed Deviations)~~
~~(3) Forward Scheduling~~	~~$1.489 per schedule~~
~~(4) Market Usage and Services~~	~~$.798/MWh~~
~~(5) Settlement, Metering and Client Relations~~	~~$500 per month~~

Attachment F

Data to be Provided by MID to ISO

Data Currently Provided to the CAISO via ICCP from MID SCADA System	Additional Data to be Provided to the CAISO			
	Substation	Element	Description	Data Type
McClure Unit 1 Mw				
McClure Unit 1 Mv				
McClure Unit 2 Mw				
McClure Unit 2 Mv				
McClure 115 Kv				
	McClure	CB 8084	Circuit Breaker	Status
	McClure	CB 9081	Circuit Breaker	Status
	McClure	CB 9083	Circuit Breaker	Status
	McClure	CB 9086	Circuit Breaker	Status
	McClure	McClure-Claus 115 kV	Line	MW
	McClure	McClure-Claus 115 kV	Line	MVAR
	McClure	McClure-Santa Cruz 115 kV	Line	MW
	McClure	McClure-Santa Cruz 115 kV	Line	MVAR
New Hogan Unit 1 Mw				
New Hogan Unit 1 Mv				
New Hogan Unit 2 Mw				
New Hogan Unit 2 Mv				
Parker - Walnut Mw				
Parker - Walnut Mv				
Parker - Walnut 230 Kv				
Parker 230 Kv				
	Parker	CB 1A	Circuit Breaker	Status
	Parker	CB 1B	Circuit Breaker	Status
	Parker	CB 2301	Circuit Breaker	Status
	Parker	CB 2302	Circuit Breaker	Status
	Parker	CB 2303	Circuit Breaker	Status
	Parker	CB 2304	Circuit Breaker	Status
	Parker	CB 2A	Circuit Breaker	Status
	Parker	CB 2B	Circuit Breaker	Status
	Parker	CB 6417	Circuit Breaker	Status
	Parker	Parker-Westley 230 kV	Line	MW
	Parker	Parker-Westley 230 kV	Line	MVAR
	Parker	TRAN 1	Transformer	MW
	Parker	TRAN 1	Transformer	MVAR
	Parker	TRAN 1 LSIDE CB	Circuit Breaker	Status
	Parker	TRAN 2	Transformer	MW
	Parker	TRAN 2	Transformer	MVAR
	Parker	TRAN 2 LSIDE CB	Circuit Breaker	Status
	Parker	TRAN 3	Transformer	MW
	Parker	TRAN 3	Transformer	MVAR
Standiford Metering Tower 1 Mw				
Standiford Metering Tower 1 Mv				
Standiford Metering Tower 1 115 Kv				
Standiford Metering Tower 2 Mw				
Standiford Metering Tower 2 Mv				
Standiford Metering Tower 2 115 Kv				

Data Currently Provided to the CAISO via ICCP from MID SCADA System	Additional Data to be Provided to the CAISO			
	Substation	**Element**	**Description**	**Data Type**
	Standiford	CB 901	Circuit Breaker	Status
	Standiford	CB 902	Circuit Breaker	Status
	Standiford	CB 903	Circuit Breaker	Status
	Standiford	CB 904	Circuit Breaker	Status
	Standiford	CB 905	Circuit Breaker	Status
	Standiford	CB 906	Circuit Breaker	Status
	Standiford	CB 907	Circuit Breaker	Status
	Standiford	CB 908	Circuit Breaker	Status
	Standiford	CB 909	Circuit Breaker	Status
	Standiford	CB 910	Circuit Breaker	Status
	Standiford	CB 930	Circuit Breaker	Status
	Standiford	Standiford-Claus 115 kV	Line	MW
	Standiford	Standiford-Claus 115 kV	Line	MVAR
	Standiford	Standiford-Santa Cruz 115 kV	Line	MW
	Standiford	Standiford-Santa Cruz 115 kV	Line	MVAR
	Standiford	TRAN 1	Transformer	MW
	Standiford	TRAN 1	Transformer	MVAR
	Standiford	TRAN 1 LSIDE CB	Circuit Breaker	Status
	Standiford	TRAN 2	Transformer	MW
	Standiford	TRAN 2	Transformer	MVAR
	Standiford	TRAN 2 LSIDE CB	Circuit Breaker	Status
	Standiford	TRAN 3	Transformer	MW
	Standiford	TRAN 3	Transformer	MVAR
	Standiford	TRAN 3 LSIDE CB	Circuit Breaker	Status
Stone Drop Mw				
Stone Drop Mv				
Woodland Unit 1 Mw				
Woodland Unit 1 Mv				
Woodland Unit 2 Mw				
Woodland Unit 2 Mv				
Woodland 69 Kv				
Westley - Parker Mw				
Westley - Parker Mv				
Westley - Parker 230 Kv				
Westley - Walnut Mw				
Westley - Walnut Mv				
Westley - Walnut 230 Kv				
Westley - Tracy Mw				
Westley - Tracy Mv				
Westley - Tracy 230 Kv				
Westley - Los Banos Mw				
Westley - Los Banos Mv				
Westley - Los Banos 230 Kv				
Westley - Tesla 230 Kv				

Data Currently Provided to the CAISO via ICCP from MID SCADA System	Additional Data to be Provided to the CAISO			
	Substation	**Element**	**Description**	**Data Type**
Don Pedro MID Mw				
Don Pedro MID Mv				
Don Pedro MID 69 Kv				
Don Pedro Unit 1 Mw				
Don Pedro Unit 1 Mv				
Don Pedro Unit 2 Mw				
Don Pedro Unit 2 Mv				
Don Pedro Unit 4 Mw				
Don Pedro Unit 4 Mv				
Don Pedro TID 69 Kv				
	Don Pedro	CB 110	Circuit Breaker	Status
	Don Pedro	CB 111	Circuit Breaker	Status
	Don Pedro	CB 112	Circuit Breaker	Status
	Don Pedro	Don Pedro-North Line 69 kV	Line	MW
	Don Pedro	Don Pedro-North Line 69 kV	Line	MVAR
	Don Pedro	Don Pedro-South Line 69 kV	Line	MW
	Don Pedro	Don Pedro-South Line 69 kV	Line	MVAR
MID Total Intertie Mw				
MID Total Generation Mw				
MID Total System Load Mw				
	Claus	BUS	115 kV Bus	KV
	Claus	CB 6101	Circuit Breaker	Status
	Claus	CB 9001	Circuit Breaker	Status
	Claus	CB 9006	Circuit Breaker	Status
	Claus	CB 9009	Circuit Breaker	Status
	Claus	CB 9021	Circuit Breaker	Status
	Claus	Claus-McClure 115 kV	Line	MW
	Claus	Claus-McClure 115 kV	Line	MVAR
	Claus	Claus-Standiford 115 kV	Line	MW
	Claus	Claus-Standiford 115 kV	Line	MVAR
	Claus	TRAN 1	Transformer	MW
	Claus	TRAN 1	Transformer	MVAR
	Santa Cruz	BUS	115 kV Bus	KV
	Santa Cruz	CB 9070	Circuit Breaker	Status
	Santa Cruz	CB 9071	Circuit Breaker	Status
	Santa Cruz	CB 9072	Circuit Breaker	Status
	Santa Cruz	CB 9073	Circuit Breaker	Status
	Santa Cruz	Santa Cruz-McClure 115 kV	Line	MW
	Santa Cruz	Santa Cruz-McClure 115 kV	Line	MVAR
	Santa Cruz	Santa Cruz-Standiford 115 kV	Line	MW
	Santa Cruz	Santa Cruz-Standiford 115 kV	Line	MVAR
	Santa Cruz	TRAN 1	Transformer	MW
	Santa Cruz	TRAN 1	Transformer	MVAR
	Santa Cruz	TRAN 2	Transformer	MW
	Santa Cruz	TRAN 2	Transformer	MVAR