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October 30, 2009

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER10-____-000
Amendment to Extend and Modify Grid Management Charge

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") submits this filing to extend the current Grid Management Charge ("GMC") until December 31, 2010, with one modification. [1] The one modification would revise the calculation of the market usage-forward energy ("MU-FE") component of the Grid Management Charge. The ISO respectfully requests that the tariff changes contained in this filing become effective on January 1, 2010.

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger.

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[1] The ISO submits this filing pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the ISO's tariff, and except where otherwise noted herein, references to section numbers are references to sections of the tariff.

II. Background

A. Grid Management Charge

The GMC is the rate through which the ISO recovers its administrative and operating costs. The GMC operates on a formula basis, subject to certain restrictions. The basic design of the GMC formula rate derives from a settlement that established the GMC rate design from January 1, 2004, through December 31, 2006. The settlement was accepted by the Commission's September 22, 2005, Order in Docket No. ER04-115.[2] Under the original rate design, the ISO was authorized to implement changes to the GMC charges by applying the GMC formula rate to the ISO's budgeted revenue requirement, as long as the ISO's annual budget does not exceed $195 million. That GMC rate design reflected the costs incurred in operating the ISO's markets as they existed prior to the implementation of the ISO's new market design (formerly known as the Market Redesign and Technology Upgrade) on April 1, 2009. Its use was extended a number of times. The final extension was to terminate on December 31, 2010, or the implementation of the new market design, whichever was earlier.[3]

On February 20, 2008, the ISO filed with the Commission a modified GMC to take effect upon implementation of the ISO's new market design, with a new cap of $197 million. The Commission conditionally approved the modified GMC on December 19, 2008.[4] The Commission directed two changes to the rate at the suggestion of the Northern California Power Authority. The first concerned a sentence that had been inadvertently omitted. The second concerned the MU-FE component of the GMC, and is discussed below.

B. Market Usage-Forward Energy Charge

The MU-FE charge is designed to recover the portion of the ISO's costs of administering its markets that is associated with forward energy purchases and sales.[5] As filed, the GMC netted forward purchases and sales against inter-

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2 *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶61,329 (2009).

3 *See Cal. Indep. Sys. Operator Corp.*, Docket No. ER06-1281, Letter Order dated September 6, 2006; *Cal. Indep. Sys. Operator Corp.*, Docket No. ER08-135, Letter Order dated December 19, 2007, Docket No. ER09-235, dated December 2, 2008).

4 *Cal. Indep. Sys. Operator Corp.*, 125 FERC ¶ 61,338 (2008).

5 In the course of discussing the instant proposal with stakeholders the ISO realized that the term "energy purchases and sales" is potentially confusing because it may be read to include only forward energy that was scheduled based on submitted economic bids and not submitted self-schedules. As explained below, however, the appropriate cost-causation basis for the charge is the full amount of energy scheduled in the integrated forward market irrespective of whether energy schedules resulted from submitted economic bids or self-schedules. Moreover the current implementation of the charge does interpret the existing tariff language to include all scheduled energy, not just energy scheduled based on economic bids. Therefore, to avoid any potential confusion, the proposed tariff language uses the tariff defined term "day-ahead schedules" rather than "energy purchases and sales."

scheduling coordinator trades in calculating the rate. In comments on the February 20, 2008, filing, the Northern California Power Authority raised a question as to whether the amount of energy in the day-ahead market subject to the MU-FE charge would be offset (1) solely by "physical" inter-scheduling coordinator trades (*i.e.* trades at PNodes, which are subject to physical validation based on energy bids or self-schedules from a resource at the location of the PNode); or, (2) by both physical and financial inter-scheduling coordinator trades (*i.e.* trades at aggregated P-Nodes, such as the Default Load Aggregation Points or Trading Hubs, which are not subject to physical validation).

In its January 21, 2009, compliance filing, the ISO submitted revised tariff language clarifying that the MU-FE charge offset was intended to include only physical inter-scheduling coordinator trades. In comments filed on February 11, 2009, in response to the compliance filing, NCPA again raised concerns about the exclusion of financial inter-scheduling coordinator trades in the calculation. Upon further consideration of these comments, the ISO, in its February 26, 2009, answer to the NCPA comments, agreed that it was not appropriate to treat "financial" and "physical" trades differently and, therefore, agreed that they both should be used in the allocation formula to offset energy charges in the day-ahead market.

Specifically, the ISO reasoned that both types of inter-scheduling coordinator trades are, in fact, financial. The purpose of both types of trades is to allow for contractual delivery of bilateral energy contracts at agreed-upon locations and to "reverse" the ISO charges from one party to its counter party. The trades are, thus, a purely financial service. Accordingly, the ISO agreed that that it was appropriate to treat both types of trades in the same manner, netting inter-scheduling coordinator trades at both P-Nodes and aggregated P-Nodes. On March 30, 2009, the Commission directed the ISO to submit a compliance filing with revised tariff language reflecting the position set forth in its February 26, 2009, answer.[6] The ISO submitted that compliance filing on March 31, 2009. The modified GMC rate became effective on April 1, 2009.

Subsequently, the Western Power Trading Forum, the Financial Institutions Energy Group and the Sacramento Municipal Utility District submitted late-filed requests for intervention, protests and comments regarding the application of the MU-FE charge to inter-scheduling coordinator trades. The expressed concerned that, as applied, the rate might result in over-collections. They also questioned whether netting inter-scheduling coordinator energy trades appropriately reflected the ISO's costs in handling inter-scheduling coordinator trades. In an answer, the ISO stated that it would address alternative methods of cost recovery for the inter-scheduling coordinator trades in a future stakeholder process. On July 14, 2009, the Commission accepted the ISO's March 31, 2009 compliance filing, granted the late interventions, but ruled that the protest and

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[6] *Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,289 (2009).

comments were outside the scope of issues raised by the ISO's compliance filing.[7]

III. Stakeholder Process

Consistent with its answer to the protests and comments on its compliance filing,[8] the ISO initiated a stakeholder process on August 3, 2009, regarding the application of the MU-FE charge to inter-scheduling coordinator trades in the day-ahead market. The ISO posted an issue paper posing two options for consideration and discussion at an August 18, 2009 stakeholder meeting.

Both options would remove inter-scheduling coordinator energy trades from the billing determinants to which the market usage charge code formula would be applied. Accordingly, inter-scheduling coordinator trades, whether physical or financial, would no longer be netted against energy trades in the day-ahead market and would be only subject to the separate per schedule charge currently in effect. The two options differed with regard to whether the MU-FE charge would continue to be applied to "net" energy schedules (the absolute value of the net of energy demand schedules (load and exports) against energy supply schedules (generation and imports)) or to "gross" energy schedules, representing the total MWh of both energy supply schedules and energy demand schedules in the day-ahead market.

Given the nature of the costs the MU-FE charge is designed to recover, namely the costs of operating the ISO's forward energy market, the ISO believes that the gross approach would be the more appropriate approach based on cost causation. This conclusion is based on a key property of the ISO's new market structure implemented on April 1, 2009. The "integrated" nature of the new day-ahead integrated forward market means that all energy scheduled to utilize the grid must be processed through the day-ahead market. In the integrated forward market the functions of energy trading (buying and selling), energy self-scheduling, congestion management and scheduling of transmission usage are all performed in an integrated fashion by a single set of market processes and systems. Thus the most appropriate cost causation basis for the MU-FE charge would be the full amount of energy scheduled in the day-ahead market, including both supply and demand, irrespective of whether that energy was scheduled based on submitted economic bids or submitted self-schedules. (The last point also explains why, as stated earlier, the ISO is now proposing in its submitted tariff language to refer to scheduled energy rather than energy purchases and sales, as in the original tariff provisions.) Nevertheless, in keeping with the ISO's

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[7] *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,021 (2009), *reh'g pending.*

[8] The ISO addressed the over-collection issue by reducing the market usage forward energy charge on August 1, 2009 and October 1, 2009, consistent with Appendix F of the ISO Tariff.

normal stakeholder process of starting with an issue paper rather than an ISO proposal, the ISO did not express a preference for either the net or the gross option in the August 3 issue paper.

Based on stakeholder comments and a financial impact analysis provided to individual participants, the ISO posted a straw proposal on August 28, 2009. The ISO noted that both options resolved stakeholder concerns by removing inter-scheduling coordinator energy trades from the MU-FE charge formula. Although the ISO concluded that the gross option better reflected cost causation principles, it was concerned that applying the charge to "gross" energy schedules would result in substantial cost impacts to certain market participants. Because the ISO believed that cost impacts should also be taken into consideration when revising cost allocation rules, it proposed the netting option. A second stakeholder meeting was held on September 15, 2009, to discuss the straw proposal.

In comments and at the meeting, some stakeholders continued to support the netting option but many others took issue with the ISO's proposal to continue netting. These stakeholders suggested that rather than continue netting load and generation, the ISO should develop a mitigated approach that would reduce cost impacts while retaining the cost causation principles reflected in the gross energy option. Specifically, Powerex proposed that a modified "gross" approach be adopted, whereby the MU-FE charge would apply only to the "greater of" supply and demand MWhs in day-ahead schedules.

Following the September 15 stakeholder meeting, ISO staff verified that the "greater of" solution was feasible and could be implemented in the ISO settlements system. Staff informally contacted almost all interested stakeholders, including those with both supply and demand, to discuss this approach. In addition, the ISO conducted another stakeholder conference call on September 30, 2009, to provide an opportunity for all stakeholders to consider the proposal, ask questions and offer comments.

The ISO posted its final proposal on October 2, 2009, proposing (1) to eliminate inter-scheduling coordinator trades from the MU-FE charge code calculation; (2) to eliminate "netting" of forward energy from the calculation; and (3) to implement the "greater of" solution described above in the MU-FE rate calculation and allocation. The ISO proposed that the "greater of" solution would remain in place on an interim basis until the ISO undertakes a new cost of service study and considers, with its stakeholders, necessary changes to the grid management charge rate design. On October 12, 2009, interested parties submitted comments on the final proposal. The ISO conducted a final stakeholder conference call on October 21, 2009. A matrix of stakeholder positions, as provided to the ISO's Board of Governors, is attached as Exhibit C.

IV. Board Consideration

The ISO Governing Board considered the proposed amendment on October 29, 2009. In addition to reviewing Management's memorandum to the board and the matrix of stakeholder comments, the ISO Governing Board received oral comments from a number of stakeholders. The ISO Governing Board unanimously endorsed Management's proposal. A copy of Management's memorandum to the Board is included as Attachment D.

V. Proposed Tariff Revisions

The proposed amendment would extend the current GMC, with the $197 million revenue requirement cap, until December 31, 2010. This entails only one tariff modification: in Appendix F, Schedule 1, Part D, the year "2010" is changed to "2011." Stakeholders have not expressed objections to such an extension, except to the degree it includes the modification of the MU-FE charge.

Consistent with the discussion above, the ISO also proposes to modify the MU-FE charge. Appendix F, Schedule 1, Section A.7 of the ISO Tariff currently provides that "the rate for the Day-Ahead Market for Energy will be based on MWh of net Energy purchases or sales in the [day-ahead market], offset by MWh of net Energy associated with Inter-[Scheduling Coordinator] Trades of Energy in the [Day-Ahead Market]." The ISO proposes to revise this language to (1) exclude inter-scheduling coordinator trades from the calculation; (2) refer to day-ahead energy schedules rather than purchases and sales; (3) eliminate "netting" of purchases and sales, or of supply and demand; and (4) calculate the charge based on the greater of total supply schedules or total demand schedules. Thus the rate would be based on the sum, for all scheduling coordinators and all hours of the invoice period, of the greater of the amount of MWh associated with each scheduling coordinator's day-ahead schedule of supply or the amount associated with its day-ahead schedule of demand for each hour.

Analogously, Appendix F, Schedule 1, Section E provides for the charge to each scheduling coordinator to be based on the rate calculated per Section A times the sum, for all hours of the invoice period, of the greater of the amount of MWh associated with the scheduling coordinator's day-ahead schedule of supply or the amount associated with its day-ahead schedule of demand for each hour.

The ISO has concluded that the use of a gross, rather than net, charge is most consistent with cost causation. All energy that participants schedule uses the ISO grid and market systems and contributes to the administrative costs of the systems, regardless of whether the energy is bought and sold in the spot markets, or self-scheduled from a load-serving entity's own generation or a bilateral contract. The ISO incurs these costs both for schedules that are responsible for paying market congestion charges and for those that are exempt from market congestion charges (such as Existing Contract self-schedules). Under the ISO's new market structure implemented on April 1, 2009, all bids submitted to the ISO markets – including self-schedules as well as economic bids – must be included in the congestion management process performed by the ISO's optimization software. The fact that a party's bids may consist of balanced self-schedules does not lessen the need for the ISO market systems to manage the impacts of those bids in managing congestion, scheduling transmission service and clearing the markets.

The ISO's proposal eliminates inter-scheduling coordinator trades from the calculation and allocation of the MU-FE charge because these financial instruments do not figure into the market optimizations and therefore do not utilize the market services recovered through the MU-FE charge as energy supply and demand schedules do. The same cannot be said for the balanced portion of a scheduling coordinator's energy schedule. All supply and demand must be included in the ISO's market optimization and the ISO therefore incurs administrative market costs for all supply and demand. Netting supply schedules and demand schedules would ignore this cost causation and distort the allocation.

At the same time, the ISO recognizes that elimination of netting could result in substantial rate impacts for some scheduling coordinators. The ISO therefore proposes to moderate such impacts by basing the allocation on the greater of a scheduling coordinator's supply or demand schedules, rather than on the absolute sum of its supply and demand schedules as a gross approach would do.

The ISO posted draft tariff language and notified stakeholders via market notice on October 8, 2009. Stakeholders had an opportunity to submit comments by October 16 and a conference call was held on October 21. In response to stakeholder concerns, revised draft tariff language was posted on October 20 and stakeholders were notified by market notice so that the revised language was available for discussion on the conference call.

V. Effective Date

The ISO requests that the Commission make the tariff revisions contained in the instant filing effective January 1, 2010.

VI. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be put on the official service list established by the Commission with respect to this submittal:

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* Individuals designated for service pursuant to Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3).

VII. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO Website.

VIII. Attachments

The following attachments, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised Tariff sheets that incorporate the proposed changes described above
Attachment B	The proposed changes to the Tariff shown in black-line format
Attachment C	Stakeholder comment matrix.
Attachment D	Board memorandum.

IX. Conclusion

For the foregoing reasons, the Commission should accept the proposed tariff changes contained in the instant filing to become effective on January 1, 2010. Please contact the undersigned if you have any questions regarding this matter.

Respectfully submitted,

Michael E. Ward

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Attachment A – Clean Sheets

2010 GMC Extension Amendment Filing

Fourth Replacement CAISO Tariff

October 30, 2009

5. The rate in $/MWh for the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights 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 Balancing Authority Area Load associated with Transmission Ownership Rights.

6. The rate in $ per Schedule or $ per Inter-SC Trade 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 Day-Ahead and HASP Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service and Residual Unit Commitment Bids and all Inter-SC Trades, including Inter-SC Trades of IFM Load Uplift Obligations. This charge will be assessed separately with respect to Schedules and Inter-SC Trades.

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, Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with Uninstructed Imbalance Energy for Participating Intermittent Resources netted over the Trading Month and all other Uninstructed Imbalance Energy being netted within a Settlement Interval) in MWh. A Market Usage Charge rate will be calculated separately for two sets of CAISO Markets: (i) the Ancillary Services and RTM rate will be based on MWh of purchases and sales of Ancillary Services in the DAM, the HASP, and the RTM, MWh of Instructed Imbalance Energy, and MWh of Uninstructed Imbalance Energy netted over the Settlement Interval; and (ii) the rate for the Day-Ahead Market for Energy will be based on MWh of Day-Ahead Schedules. The rate for the Day-Ahead Market for Energy will be based on the sum, for all Scheduling Coordinators and all Settlement Periods, of the greater of the amount of MWh associated with each Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $1000.00 per month, per Scheduling Coordinator ID Code (SCID) with an invoice value other than $0.00 in the current Trading Month.

For a Scheduling Coordinator for a Load following MSS, the GMC service charges set forth in above shall be applied as set forth in Section 11.22.3 of the CAISO Tariff.

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 CAISO's filing or posting on the CAISO Website, as applicable, if the estimated revenue collections for that component, on an annual basis, change by more than five percent (5%) or $1 million, whichever is greater, 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 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 change of more than five percent (5%) or $1 million, whichever is greater, from the estimated revenue collections provided in the annual informational filing.

At least one month prior to the CAISO Governing Board meeting scheduled to consider approval of the proposed budget, the CAISO will hold a meeting open to all stakeholders to discuss the details of the CAISO'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 CAISO will endeavor to host a workshop on the CAISO's budget preparation process in advance of the meeting to better prepare stakeholders.

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

The CAISO 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 CAISO Governing Board.

Budget Posting

After the approval of the annual budget by the CAISO Governing Board, the CAISO will post on the CAISO Website the CAISO 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 any Budget Year does not exceed $197 million, the CAISO 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 CAISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for a Budget Year that exceeds $197 million, the CAISO must submit an application to the FERC under FPA Section 205. In any event, the CAISO shall submit a filing under FPA Section 205 for approval of the Grid Management Charge to be effective no later than January 1, 2011. In such filing, the CAISO may revise the Grid Management Charge rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

The CAISO 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 CAISO Governing Board. The periodic financial reports will be posted on the CAISO 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 service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E and to Part F of this Schedule 1. Expenses projected to be recorded in each cost center shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. In the event the CAISO 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 CAISO 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 CAISO's existing bond offerings shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. Capital expenditures shall be allocated among the charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1, 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 Charge 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.

The cost allocation factors in Tables 1, 2, and 3 to this Schedule 1 include the following association of factors to the components of the Grid Management Charge, subject to Part F of this Schedule 1:

CRS: This factor is the allocation of costs to the Core Reliability Services – Demand Charge and Core Reliability Services - Energy Exports Charge.

ETS: This factor is the allocation of costs to the Energy Transmission Services – Net Energy Charge and Energy Transmission Services – Uninstructed Deviations Charge, subject to Section 2 of this Part E.

CRS/ETS TOR: This factor is the allocation of costs to Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge for the assessment of the Core Reliability Services – Demand Charge, Core Reliability Services – Energy Exports Charge, and the Energy Transmission Services – Net Energy Charge to Metered Balancing Authority Area Load served over Transmission Ownership Rights.

FS: This factor is the allocation of costs to the Forward Scheduling Charge.

MU: This factor is the allocation of costs to the Market Usage Charge, except for the application of the Market Usage Charge to purchases or sales of Energy in the Day-Ahead Market.

MU-FE: This factor is the allocation of costs to the Market Usage Charge as applied to Day-Ahead Schedules. For each Scheduling Coordinator, the charge for the Day-Ahead Market for Energy will be based on the sum, for all Settlement Periods, of the greater of the amount of MWh associated with the Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

SMCR: This factor is the allocation of costs to the Settlements, Metering, and Client Relations Charge.

Attachment B - Blacklines

2010 GMC Extension Amendment Filing

Fourth Replacement CAISO Tariff

October 30, 2009

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CAISO TARIFF APPENDIX F

Rate Schedules

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CAISO TARIFF APPENDIX F
Schedule 1

Grid Management Charge

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

The Grid Management Charge consists of the following 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 Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge, (6) the Forward Scheduling 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 percent (34%) of the sum of all Scheduling Coordinators' metered non-coincident peak Demands 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 Demand 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 percent (66%) of the standard Core Reliability Services – Demand Charge rate.

2. The rate in \$/MWh for the Core Reliability Services – Energy Exports 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, excluding each Scheduling Coordinator's Energy Exports associated with Transmission Ownership Rights.

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 Balancing Authority Area Load, excluding each Scheduling Coordinator's Metered Balancing Authority Area Load associated with Transmission Ownership Rights.

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 Imbalance Energy (netted within a Settlement Interval summed over the calendar month) in MWh; provided that the rate for each Scheduling Coordinator's Participating Intermittent Resources will be assessed against the Uninstructed Imbalance Energy of such Participating Intermittent Resources netted over the Trading Month.

5. The rate in \$/MWh for the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights 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 Balancing Authority Area Load associated with Transmission Ownership Rights.

6. The rate in $ per Schedule or $ per Inter-SC Trade 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 Day-Ahead and HASP Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service and Residual Unit Commitment Bids and all Inter-SC Trades, including Inter-SC Trades of IFM Load Uplift Obligations. This charge will be assessed separately with respect to Schedules and Inter-SC Trades.

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, Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with Uninstructed Imbalance Energy for Participating Intermittent Resources netted over the Trading Month and all other Uninstructed Imbalance Energy being netted within a Settlement Interval) in MWh. A Market Usage Charge rate will be calculated separately for two sets of CAISO Markets: (i) the Ancillary Services and RTM rate will be based on MWh of purchases and sales of Ancillary Services in the DAM, the HASP, and the RTM, MWh of Instructed Imbalance Energy, and MWh of Uninstructed Imbalance Energy netted over the Settlement Interval; and (ii) the rate for the Day-Ahead Market for Energy will be based on MWh of Day-Ahead Schedules~~net Energy purchases or sales in the DAM, offset by MWh of net Energy associated with Inter-SC Trades of Energy in the DAM~~. The rate for the Day-Ahead Market for Energy will be based on the sum, for all Scheduling Coordinators and all Settlement Periods, of the greater of the amount of MWh associated with each Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $1000.00 per month, per Scheduling Coordinator ID Code (SCID) with an invoice value other than $0.00 in the current Trading Month.

For a Scheduling Coordinator for a Load following MSS, the GMC service charges set forth in above shall be applied as set forth in Section 11.22.3 of the CAISO Tariff.

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 D – Information Requirements

Budget Schedule

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

Within two (2) weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the CAISO'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 CAISO Governing Board, the CAISO 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 CAISO 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 CAISO's GMC (or regulators) who execute a confidentiality agreement.

The CAISO 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 CAISO Governing Board.

At least one month prior to the CAISO Governing Board meeting scheduled to consider approval of the proposed budget, the CAISO will hold a meeting open to all stakeholders to discuss the details of the CAISO'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 CAISO will endeavor to host a workshop on the CAISO's budget preparation process in advance of the meeting to better prepare stakeholders.

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

The CAISO 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 CAISO Governing Board.

Budget Posting

After the approval of the annual budget by the CAISO Governing Board, the CAISO will post on the CAISO Website the CAISO 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 any Budget Year does not exceed $197 million, the CAISO 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 CAISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for a Budget Year that exceeds $197 million, the CAISO must submit an application to the FERC under FPA Section 205. In any event, the CAISO shall submit a filing under FPA Section 205 for approval of the Grid Management Charge to be effective no later than January 1, ~~2010~~<u>2011</u>. In such filing, the CAISO may revise the Grid Management Charge rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

The CAISO 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 CAISO Governing Board. The periodic financial reports will be posted on the CAISO Website not less than quarterly.

<u>Part E – Cost Allocation</u>

1. The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E and to Part F of this Schedule 1. Expenses projected to be recorded in each cost center shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. In the event the CAISO 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 CAISO 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 CAISO's existing bond offerings shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. Capital expenditures shall be allocated among the charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1, 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 Charge 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.

The cost allocation factors in Tables 1, 2, and 3 to this Schedule 1 include the following association of factors to the components of the Grid Management Charge, subject to Part F of this Schedule 1:

CRS: This factor is the allocation of costs to the Core Reliability Services – Demand Charge and Core Reliability Services - Energy Exports Charge.

ETS: This factor is the allocation of costs to the Energy Transmission Services – Net Energy Charge and Energy Transmission Services – Uninstructed Deviations Charge, subject to Section 2 of this Part E.

CRS/ETS TOR: This factor is the allocation of costs to Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge for the assessment of the Core Reliability Services – Demand Charge, Core Reliability Services – Energy Exports Charge, and the Energy Transmission Services – Net Energy Charge to Metered Balancing Authority Area Load served over Transmission Ownership Rights.

FS: This factor is the allocation of costs to the Forward Scheduling Charge.

MU: This factor is the allocation of costs to the Market Usage Charge, except for the application of the Market Usage Charge to purchases or sales of Energy in the Day-Ahead Market.

MU-FE: This factor is the allocation of costs to the Market Usage Charge as applied to Day-Ahead Schedules~~net purchases or sales of Energy in the Day-Ahead Market~~. For each Scheduling Coordinator, the charge for the Day-Ahead Market for Energy will be based on the sum, for all Settlement Periods, of the greater of the amount of MWh associated with the Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

SMCR: This factor is the allocation of costs to the Settlements, Metering, and Client Relations Charge.

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 (ETS) category in the following tables are further apportioned to the Energy Transmission Services – Net Energy Charge and Energy Transmission Services – Uninstructed Deviations Charge subcategories in eighty percent (80%) and twenty percent (20%) ratios, respectively.

* * *

Attachment C

Attachment A

Stakeholder Process: Modification to the Market Usage Forward Energy Charge

Summary of Submitted Comments

Stakeholders submitted three rounds of written comments to the ISO on the following dates:

- Round One, August 10, 2009 response to issue paper posing two options
- Round Two, September 4, 2009 response to straw proposal
- Round Three, October 12, 2009 response to final proposal

Stakeholder comments are posted at: http://www.caiso.com/2417/2417891c4ad50.html

Other stakeholder efforts include:

- Stakeholder meeting August 18, 2009 to discuss two options
- Stakeholder meeting September 15, 2009 to discuss straw proposal
- Stakeholder call September 30, 2009 to discuss final proposal

Management Proposal	Calpine Corp. Direct Energy Dynegy J.P. Morgan Powerex Corp. RBS Sempra Commodities Western Power Trading Forum Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside	Pacific Gas and Electric Company Southern California Edison San Diego Gas and Electric Company	Northern California Power Agency	California Department of Water Resources/ State Water Project	Management Response
To remove Inter Scheduling Coordinator Trades from the Market Usage Forward Energy Charge	Support	Support	Oppose Existing methodology is just and reasonable	Support	All comments received except for one support the removal of inter scheduling coordinator trades from this calculation.
To use the "greater of" a scheduling coordinators supply or demand as the basis for billable quantity of the Market Usage Forward Energy Charge Code	Support On basis of cost causation Move towards gross billing determinant Re-evaluate in next cost of service study Six cities do oppose the gross methodology, but believe the greater of method is reasonable	Oppose Netting has been approved by FERC A scheduling coordinator with matching supply and demand should not pay for the service Do not believe netting violates cost causation principles	Oppose Existing methodology is just and reasonable Existing methodology is better aligned with a scheduling coordinators use of the forward market	Oppose The net option is reasonable The gross option could lead to double charging The greater of option does not have any supporting theory Existing Transmission Contract energy should not be assessed any MUFE charges	All energy that participants schedule utilizes the ISO grid and contributes to these costs, irrespective of whether the energy is bought and sold in the spot markets, self-scheduled from a load serving entities (LSE's) own generation or a bilateral contract, fully responsible for paying market congestion charges, or exempt from market congestion charges as is true for valid existing transmission contract (ETC) self-schedules. Fundamentally, the ISO market system is the mechanism through which parties schedule transmission service over ISO-controlled grid facilities for every MWh they want to inject into or withdraw from the ISO grid. This means, for example, that all bids submitted to the ISO markets – including self-schedules as well as economic bids – must be included in the congestion management process performed by the ISO's integrated forward market (IFM) and real time market (RTM) optimization software. The fact that a party's bids consist of balanced self-schedules, ETC or otherwise, does not lessen the need for the ISO market systems to manage the impacts of those bids in clearing the markets. Responding to the comment for double charging, the GMC charge referenced for double charging is Energy Transmission Services (ETS) which recovers the costs related to grid reliability. Market Usage Forward

Management Proposal	Calpine Corp. Direct Energy Dynegy J.P. Morgan Powerex Corp. RBS Sempra Commodities Western Power Trading Forum Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside	Pacific Gas and Electric Company Southern California Edison San Diego Gas and Electric Company	Northern California Power Agency	California Department of Water Resources/ State Water Project	Management Response
					Energy recovers the costs related to running the forward market. These charges are unrelated. The ISO's final proposal eliminates inter-scheduling coordinator trades from application of the Market Usage Forward Energy Charge, as well as eliminating the netting of load and generation from the calculation. Recognizing that these modifications will result in substantial rate impacts for some scheduling coordinators, the ISO has also proposed a "greater of" supply or demand mitigation adjustment to the formula.

Attachment D

California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Steve Berberich, Vice President of Technology and Corporate Services and Chief Financial Officer

Date: October 21, 2009

Re: **Decision on Extension of Current Grid Management Charges through 2010 with a Modification to the Market Usage Forward Energy Charge**

This memorandum requires Board action.

Executive Summary

The California Independent System Operator Corporation's (ISOs) current grid management charge (GMC) became effective with the new market implementation on April 1, 2009 and will expire by its own terms on December 31, 2009. Therefore, the grid management charge must be extended through December 31, 2010. Management proposes to extend the grid management charge formula rate and the current rate design elements, except for a modification to the market usage forward energy charge which represents about 6.6% of the 2010 revenue requirement.

The current grid management charge rate design was approved by the Federal Energy Regulatory Commission (FERC) on December 19, 2008. At the ISO's June 17, 2009, budget meeting, the ISO proposed to extend the grid management charge rate elements and the current revenue requirement cap through 2010, subject to the outcome of a separate stakeholder process to consider the imposition of grid management charges on inter-scheduling coordinator trades, an issue that previously had been raised in a FERC proceeding. Based on stakeholder comments and cost causation principles, Management proposes to eliminate inter-scheduling coordinator trades as a market usage forward energy charge billing determinant, and to apply the charge to all physical energy in the day-ahead market using the greater of a scheduling coordinator's supply or demand volume. The ISO will propose to extend the grid management charge and modify the market usage forward energy charge in a tariff amendment to be filed with the FERC by November 1, 2009.

Management is proposing the following motions:

> ***Moved, that the ISO Board of Governors approves the proposed tariff changes regarding the extension of the grid management charge through December 31, 2010 and modifications to the grid management charge market usage forward energy charge, as detailed in the memorandum dated October 21, 2009; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all of the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement this proposal.***

DISCUSSION AND ANALYSIS

Grid Management Charge Background

The basic design of the grid management charge, which is the mechanism through which the ISO recovers its administrative costs, was established in a settlement agreement with stakeholders in 2004 and approved by the FERC in 2005. That design consists of a rate formula that allocates costs to categories that correspond to ISO services, subject to an annual revenue requirement cap. As long as the ISO's revenue requirement remains below the cap, the ISO and market participants have agreed that a regulatory filing reflecting changes to the annual revenue requirement is unnecessary. The 2004 settlement contemplated that the formula rate and revenue requirement cap would remain in place until the earlier of the ISO's new market *go live* or the end of 2006. Because the new market *go live* date was extended several times after 2006, the ISO and its stakeholders agreed to extend the grid management charge formula rate and revenue requirement cap in 2006, 2007 and 2008. The 2008 extension filing provided that the grid management charge would expire on December 31, 2009, and this provision remained in place upon new market implementation. Through a stakeholder process in 2009, market participants again agreed to extend the GMC formula rate and revenue cap through 2010, subject to the changes noted in this memo. Upon Board approval, the ISO will file to extend the current GMC construct through 2010.

Extending the Current Grid Management Charge

Except for a change to the market usage forward energy charge, discussed below, Management proposes to extend the current grid management charge formula rate and the $197 million revenue requirement cap until January 1, 2011. Accordingly, the tariff change needed to implement this extension is restricted to one paragraph of the tariff, in *Appendix F, Schedule 1, Part D*. The sole change consists of changing the reference of the year from "2010" to "2011."

Modifications to the Market Usage Forward Energy Charge

As indicated above, Management proposes to modify the market usage forward energy charge. To understand the proposed modifications to this charge code, it is necessary to understand what costs the charge is intended to recover. The market usage forward energy charge is designed to recover, *inter alia,* costs for systems and operations associated with running the forward market. The charge is based on total megawatts scheduled in the forward market, and the current formula nets a scheduling coordinator's supply and demand volume, then subtracts the MWh's of inter scheduling coordinator trades (ISTs) to apply the charge calculation.

Stakeholders questioned whether it was appropriate to apply the market usage forward energy charge to ISTs when they were just executing ISTs in the day-ahead market and not actually scheduling physical energy. Subsequently, certain parties filed protests with the FERC. Certain stakeholders were alleged that the rate was unreasonable when applied to market participants that were only executing ISTs and would result in an over collection of ISO costs. Stakeholders also questioned whether netting physical energy appropriately reflected the ISO's costs for running the forward market. As the ISO monitored collections under the new market, over collection conditions did develop and the ISO reduced the market usage forward energy charge on August 1, 2009 (from \$0.43 per MWh to \$0.30 MWh) and October 1, 2009 (from \$0.30 MWh to \$0.26 MWh).

The ISO addressed the issue of application of the charge to ISTs in the day-ahead market in a stakeholder proceeding that was initiated on August 3, 2009 when the ISO posted an issue paper posing two options for consideration. The ISO subsequently discussed these options at an August 18, 2009 stakeholder meeting.

Both options contemplated removing ISTs from the billing determinants to which the market usage charge code formula applies. Accordingly, ISTs would no longer be netted against all energy trades in the day-ahead market and would be only subject to a flat fee per schedule. However, the two options differed with regard to whether the market usage forward energy charge would continue to be applied to "net" energy (the product of netting supply and demand) or to "gross" energy consisting of all energy (the product of gross supply and demand) in the day-ahead market.

Based on stakeholder comments and a financial impact analysis provided to individual participants, the ISO posted a straw proposal on August 28, 2009 suggesting that the "netting" option was the most appropriate approach. Both options resolved stakeholder concerns by removing inter-scheduling coordinator energy trades from the market usage forward energy charge formula, but applying the charge to "gross" energy resulted in substantial bill impacts to certain market participants. The ISO noted that while the "gross" option better reflects cost causation principles, significant bill impacts should also be taken into consideration. A second stakeholder meeting was held on September 15, 2009, to discuss the straw proposal.

In comments and at the meeting, some stakeholders expressed their support for the netting option, but the majority took issue with the ISO's proposal to continue netting. These stakeholders suggested that rather than continue netting supply and demand, the ISO should adopt a mitigation solution that would reduce bill impacts while retaining the cost causation principles reflected by the gross energy option. Specifically, Powerex proposed that the "gross" approach be adopted, but for those scheduling coordinators with both supply and demand the market usage forward energy charge would be applied to the "greater of" their supply or demand MWhs in the day-ahead market.

Following the September 15 stakeholder meeting, ISO staff verified that the "greater of" mitigation solution proposed by Powerex was feasible and could be implemented in the ISO settlements system. Staff informally contacted almost all interested stakeholders, particularly those with both supply and demand in their portfolio, to discuss this mitigation approach. In addition, the ISO held a stakeholder conference call on September 30, 2009, to provide stakeholders an additional opportunity to discuss the proposal and ask questions. Following those consultations and the public meeting, the ISO posted its final proposal on October 2, 2009, in which it proposed to:

1) Eliminate inter-scheduling coordinator trades from the market energy forward usage charge code calculation;

2) Eliminate "netting" forward energy from the calculation; and

3) Implement the "greater of" mitigation solution in the market usage forward energy calculation.

The ISO agreed that the "greater of" mitigation solution would remain in place on an interim basis until the ISO undertakes a new cost of service study and considers, with its stakeholders, necessary changes to the grid management charge rate design. On October 12, 2009, interested parties submitted comments on the final proposal.

POSTIONS OF THE PARTIES

At the initial June 17, 2009 budget meeting, the July 22, 2009 grid management charge meeting and again at the October 1, 2009 budget meeting, Management informed stakeholders of the proposal to extend the current tariff provisions (except for the change to the market usage forward energy charge) through 2010. Stakeholders were provided an opportunity to submit comments regarding the extension proposal at each meeting. In response, parties specifically requested that the extension request be limited to the year 2010. Certain parties also advised the ISO that if the market usage forward energy charge issue was not satisfactorily resolved, they would oppose the grid management charge extension proposal. Stakeholders did not raise any other issues regarding the grid management charge extension.

The ISO conducted the market usage forward energy initiative as a separate process, and stakeholders had three opportunities to submit written comments for consideration, in addition to providing comments at two stakeholder meetings and one conference call. Aside from eliminating ISTs from the market usage forward energy charge calculation, there was no consensus among stakeholders regarding the netting and bill impact mitigation issues.

Stakeholder comments on the final proposal for market usage forward energy charge are detailed in the attached stakeholder matrix.

MANAGEMENT RECOMMENDATION

There is broad support to eliminate ISTs from the billing determinants used to calculate the charge for market usage forward energy, and Management recommends that change. However, there is no consensus on how the charge should be structured for the actual amount of physical energy scheduled. Some scheduling coordinators stated that removing ISTs from the charge is sufficient to resolve the issue, and that netting physical energy should remain on the basis of FERC already approving that methodology and that the balanced part of a portfolio does not play a role in the forward market. However, Management believes that all MWh's of physical energy scheduled in the day-ahead market do factor into the integrated forward market calculations and should therefore be subject to this charge from a cost causation standpoint. The gross quantity of a scheduling coordinators supply plus demand must be processed through SIBR and addressed by the market optimization in order to perform congestion management, irrespective of whether that supply and demand was economically bid, self-scheduled, or was scheduled under an existing transmission contract. The ISO acknowledges that shifting to a gross calculation at this time would create a significant cost shift to those scheduling coordinators with both supply and demand in their portfolio. To mitigate the bill of a shift from net to gross, the ISO is proposing the "greater of" approach as a solution. The "greater of" proposal will only look at the larger of an SC's supply or demand MWh's in their portfolio and assess the charge on that basis, rather than the sum of their supply and demand.

Management's proposed solution accomplishes the objectives of redesigning this charge code while considering the impacts to all market participants. It removes ISTs from the equation, while also mitigating the bill impact through a "greater of" methodology. This solution is intended to be in place until a full cost of service study is completed in the future.