Appendix C

Locational Marginal Price

The CAISO shall calculate the price of Energy at Generation PNodes, Scheduling Points, and Aggregated Pricing Nodes, as provided in the CAISO Tariff. LMPs can be set by Bids to sell or purchase Energy. The CAISO establishes Trading Hub prices and LAPs as provided in the CAISO Tariff. The LMPs at PNodes, including Scheduling Points, and Aggregated Pricing Nodes include separate components for the marginal cost of Energy, Marginal Cost of Congestion, and Marginal Cost of Losses. As provided in Sections 6.5.3.2.2 and 6.5.5.2.4, Day-Ahead Market LMPs are calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Market for Energy and for each Dispatch Interval for the Real-Time LMPs.

A. LMP Composition

In each hour of the Day-Ahead Market for Energy, the CAISO calculates the LMP for each PNode, which is equal to the marginal cost of Energy available at the PNode in the hour, based on the Bids of sellers and buyers selected in the Day-Ahead Market for Energy as specified in the Day-Ahead Schedule. The CAISO designates a Reference Bus, r, for calculation of the System Marginal Energy Cost (SMECr). The CAISO uses a distributed Reference Bus to define an aggregate value of Energy for the CAISO Balancing Authority Area. The Locational Marginal Prices are not determined by resources that are not eligible to set the Locational Marginal Price, which includes resources that have constraints that prevent them from being marginal. For each bus other than the Reference Bus, the Transmission Provider determines separate components of the LMP for the marginal cost of Energy, Marginal Cost of Congestion, and Marginal Cost of Losses relative to the Reference Bus, consistent with the following equation:

$LMP_i = SMEC_r + MCC_i + MCL_i$

$LMP_r = SMEC_r$

where:

- $SMEC_r$ is the LMP component representing the marginal cost of Energy (also referred to as λ) at the Reference Bus, r (System Marginal Energy Cost).

- MCC_i is the LMP component representing the Marginal Cost of Congestion (also referred to as ρ) at bus i relative to the Reference Bus.
- MCL_i is the LMP component representing the Marginal Cost of Losses (also referred to as γ) at bus i relative to the Reference Bus.

B. The System Marginal Energy Cost Component of LMP

The SMEC shall be the same for each location throughout the system. SMEC is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Demand, including exports and Transmission Losses) is accounted for in the network solution. For the designated reference location the CAISO will utilize a distributed Load Reference Bus for which constituent PNodes are weighted using the Reference Bus distribution factors. The Load distributed Reference Bus distribution factors are based on the Load Distribution Factors at each PNode that represents cleared Load in the Integrated Forward Market or forecast Load for MPM-RRD, RUC, HASP and RTM. In the Integrated Forward Market, in the event that the market is not able to clear based on the use of a distributed load Reference Bus, the CAISO will use a distributed generation Reference Bus for which the constituent nodes and the weights are determined economically within the running of the Integrated Forward Market based on available economic bids. In the event that the CAISO employs a distributed generation Reference Bus, it will notify Market Participants of which Integrated Forward Market runs required the use of this backstop mechanism. A distributed Load Reference Bus will be used for MPM-RRD, RUC, HASP and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding Integrated Forward Market run. Once the Reference Bus is selected, the System Marginal Energy Cost is the cost of economically providing the next increment of Energy at the distributed Reference Bus, based on submitted Bids.

C. Marginal Congestion Component Calculation

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (MCCi) component of the LMP at bus i is calculated using the equation:

$$MCC_i = -\left(\sum_{k=1}^{k} PTDF_{ik} * FSP_k\right)$$

where:

- K is the number of thermal or interface Transmission Constraints.

$PTDF_{ik}$ is the Power Transfer Distribution Factor for the generator at bus i on interface k which limits flows across that constraint when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The industry convention is to ignore the effect of losses in the determination of PTDFs.

- FSP_k is the constraint Shadow Price on interface k and is equivalent to the reduction in system cost expressed in \$/MWh that results from an increase of 1MW of the capacity on interface k.

The Shadow Price at a given binding Transmission Constraint is the value per MW of the next increment of generation that would flow across the constrained path by relaxing the binding Transmission Constraint. The PTDF of a PNode with respect to a transmission path (and direction on the path) measures the change in the power flow through the path (positive or negative, with respect to the designated direction on the path) as a result of an incremental injection at the Node, balanced by incremental change of Load at the Reference Bus.

D. Marginal Losses Component Calculation

The CAISO calculates the Marginal Cost of Losses (MCL_i) at each bus i as described in Section 27.1.1.2. The MCL component of the LMP at any bus i within the CAISO's Balancing Authority Area is calculated using the equation:

$$MCL_i = MLF_i * SMEC_r$$

Where:

- MLF_i is the marginal loss factor for PNode i to the system Reference Bus, based on an AC power flow solution. The marginal loss factor at a PNode is the incremental change in the quantity (MW) of transmission losses in the network resulting when serving an increment of Load at the PNode from the Reference Bus.
    - MLF_i is equal to $1 - \partial L/\partial G_i$, where: L is system losses, G_i is "generation injection" at PNode i, $\partial L/\partial G_i$ is the partial derivative of system losses with

respect to generation injection at bus *i*, that is, the incremental change in system losses associated with an incremental change in the generation injections at bus *i* holding constant other injection and withdrawals at all buses other than the Reference Bus and bus *i*.

- SMECr is the SMEC at the Reference Bus, r.

E. Trading Hub Price Calculation

The CAISO calculates Existing Zone Generation Trading Hub prices, as provided in Section 27.3, based on the LMP calculations described in this Attachment and in Section 27.2.

$$\text{EZ Gen Trading Hub Price}_j = \sum_{i=1}^{NG} WG_{ist} * LMP_i$$

where:

- NG is the number of Generation buses defined in the Existing Zone Generation Trading Hub *j*.
- WG_{ist} is the generation-weighting factor for bus *i* for season *s* for time period *t* representing peak or off-peak period in Existing Zone Generation Trading Hub *j*. The sum of the weighting factors must add up to 1. These weights are based on the previous years actual generation output as described in Section 27.3.

F. Load Zone Price Calculation

The CAISO calculates LAP prices based on the LMPs for a set of buses that comprise the LAP. These LAP prices represent the weighted average of the LMPs at the set of buses that comprise the LAP. The LAP bus weight is equal to the fractional share of each Load bus in the total Load in the LAP during the hour.

The price for LAP *j* is:

$$\text{LAP Price}_j = \sum_{i=1}^{NZ} WZ_i * LMP_i)$$

where:

- NZ is the number of Load buses in LAP *j*.
- WZ_i is the load-weighting factor for bus *i* in LAP *j*. The sum of the weighting factors must equal 1 (i.e., 100 percent). These weights are based on State Estimator results for similar day.

Each LAP includes only the buses of Market Participants who are in the LAP and who have Load that is represented by that LAP's definition. Market Participants that have metered Load must either be settled at a Default LAP or a Custom LAP created for each Load point of the Market Participant (nodal Settlement).

G. Intertie Scheduling Point Price Calculation

The CAISO calculates LMPs for Scheduling Points, which are represented in the FNM as PNodes or aggregations of PNodes, external to the CAISO Balancing Authority Area, through the same process that is used to calculate LMPs within the CAISO Balancing Authority Area. In some cases, facilities that are part of the CAISO Controlled Grid but are external to the CAISO Balancing Authority Area connect some Intertie Scheduling Points to the CAISO Balancing Authority Area, and in these cases the Scheduling Points are within external Balancing Authority Areas. In both of these cases, the Scheduling Points are represented in the FNM. The CAISO places injections and withdrawals at the Scheduling Point PNodes to represent Bids and Schedules whose supporting physical injection and withdrawal locations may be unknown, and the LMPs for Settlement of accepted Bids are established at the Scheduling Point PNodes.

G.1 Intertie Scheduling Point Price Calculation for IBAAs

G.1.1 Scheduling Point Prices

As described in Section 27.5.3, the CAISO's FNM includes a full model of the network topology of each IBAA. The CAISO will specify Resource IDs that associate Intertie Scheduling Point Bids and Schedules with supporting injection and withdrawal locations on the FNM. These Resource IDs may be specified by the CAISO based on the information available to it, or developed pursuant to a Market Efficiency Enhancement Agreement. Once these Resource IDs are established, the CAISO will determine Intertie Scheduling Point LMPs based on the injection and withdrawal locations associated with each Intertie Scheduling Point Bid and Schedule by the appropriate Resource ID. In calculating these LMPs the CAISO follows the provisions specified in Section 27.5.3 regarding the treatment of Transmission Constraints and losses on the IBAA network facilities. Unless otherwise required pursuant to an effective MEEA, the default pricing for all imports from the IBAA(s) to the CAISO Balancing Authority Area will be based on the

SMUD/TID IBAA Import LMP and all exports to the IBAA(s) from the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Export LMP. The SMUD/TID IBAA Import LMP will be calculated based on modeling of supply resources that assumes all supply is from the Captain Jack substation as defined by WECC. The SMUD/TID IBAA Export LMP will be calculated based on the Sacramento Municipal Utility District hub that reflects Intertie distribution factors developed from a seasonal power flow base case study of the WECC region using an equivalencing technique that requires the Sacramento Municipal Utility District hub to be equivalenced to only the buses that comprise the aggregated set of load resources in the IBAA, with all generation also being retained at its buses within the IBAA. The resulting load distribution within each aggregated set of load resources within the IBAA defines the Intertie distribution factors for exports from the CAISO Balancing Authority Area.

G.1.2 Applicable Marginal Losses Adjustment

For import Schedules to the CAISO Balancing Authority Area at the southern terminus of the California-Oregon Transmission Project at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority and the Western Area Power Administration system, the CAISO will replace the Marginal Cost of Losses at the otherwise applicable source for such Schedules with the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system, provided that the Scheduling Coordinators certify as discussed further below that the Schedules originate from transactions that use: (a) the California-Oregon Transmission Project; or (b) transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, as described further below, the Scheduling Coordinator must certify that the Schedules are subject to: (a) charges for losses by the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) charges for losses by the Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. The CAISO will establish Resource IDs that are to be used only to submit Bids, including

Self-Schedules, for the purpose of establishing Schedules that are eligible for this loss adjustment.

Prior to obtaining such Resource IDs, the relevant Scheduling Coordinator shall certify that it will only use this established Resource ID for Bids, including Self-Schedules, that originate from transactions that use: (a) the California-Oregon Transmission Project; or (b) transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, the Scheduling Coordinator must certify that the Schedules are subject to: (a) charges for losses by the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. Further, by actually using such Resource ID, the Scheduling Coordinator represents that such Bids, including Self-Schedules, that originate from transactions that use: (a) the California-Oregon Transmission Project; or (b) transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, the Scheduling Coordinator must certify that the Schedules are subject to: (a) charges for losses by the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. Schedules and Dispatches settled under such Resource IDs shall be subject to an LMP which has accounted for the Marginal Cost of Losses as if there were an actual physical generation facility at the Tracy Scheduling Point or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system as opposed to the Marginal Cost of Losses under the IBAA LMPs specified in Section G.1.1 of this Appendix. The CAISO may request information on a monthly basis from such Scheduling Coordinators to verify these certifications. Any such request shall be limited to transactions that use the designated Resource IDs during the six month prior period to the date of the request. The CAISO will calculate a re-adjustment of the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system to reflect the otherwise applicable source for such Schedules for any Settlement Interval in which the CAISO has determined that the Scheduling Coordinator's payments did not reflect transactions that meet the above specified certification requirements. Any amounts owed to the CAISO for such Marginal Cost of Losses re-adjustments will be recovered by the CAISO from the affected Scheduling Coordinator by netting the amounts owed from payments due in subsequent Settlements Statements until the outstanding amounts are fully recovered.

For export Schedules from the CAISO Balancing Authority Area at the southern terminus of the California-Oregon Transmission Project at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system, the CAISO will replace the Marginal Cost of Losses at the otherwise applicable sink for such Schedules with the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system, provided that the Scheduling Coordinator certifies, as discussed below, where the export Schedules use: (a) the California-Oregon Transmission Project; or (b) any transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, the Scheduling Coordinator must certify that the affected Schedules are charged losses by: (a) the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. The CAISO will establish Resource IDs that are to be used only to submit Bids, including Self-Schedules, for the purpose of establishing Schedules that are eligible for this loss adjustment. Prior to obtaining such Resource IDs, the relevant Scheduling Coordinator shall certify that it will only use this established Resource ID for Bids, including Self-Schedules, where the export Schedules use: (a) the California-Oregon Transmission Project; or (b) any transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition the Scheduling Coordinator must certify that the affected Schedules are charged losses by: (a) the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b)

Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. Further, by actually using such Resource ID, the Scheduling Coordinator represents that such Bids, including Self-Schedules, are used for the above specified conditions.

Schedules and Dispatches settled under such Resource IDs shall be subject to an LMP which has accounted for the Marginal Cost of Losses as if there were an actual physical generation facility at the Tracy Scheduling Point or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system as opposed to the Marginal Cost of Losses under the IBAA LMPs specified in Section G.1.1 of this Appendix. The CAISO may request information on a monthly basis from such Scheduling Coordinators to verify that schedules for such Resource IDs meet the above specified conditions. Any such request shall be limited to transactions that use the designated Resource IDs during the six month prior period to the date of the request.

The CAISO will calculate a re-adjustment of the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system to reflect the otherwise applicable sink for such Schedules for any Settlement Interval in which the CAISO has determined that the Scheduling Coordinator's payments did not reflect transactions that met the above specified conditions. Any amounts owed to the CAISO for such Marginal Cost of Losses re-adjustments will be recovered by the CAISO from the affected Scheduling Coordinator by netting the amounts owed from payments due in subsequent Settlements Statements until the outstanding amounts are fully recovered.

Appendix D

Black Start Generating Units

The following requirements must be met by Generating Units providing Black Start:

(a) Black Start Generating Units must be capable of starting and paralleling with the CAISO Controlled Grid without aid from the CAISO Controlled Grid;

(b) Black Start Generating Units must be capable of making a minimum number of starts per event (to be without aid from the CAISO Controlled Grid as determined by the CAISO);

(c) Black Start Generating Units must be equipped with governors capable of operating in the stand alone (asynchronous) and parallel (synchronous) modes.

(d) Black Start Generating Units must have Start-Up load pickup capabilities at a level to be determined by the CAISO, including total Start-Up load (MW) and largest Start-Up load (MW) for such power output levels as the CAISO may specify.

(e) All Black Start Generating Units must be capable of producing reactive Power (boost) and absorbing reactive Power (buck) as required by the CAISO to control system voltages. This requirement may be met by the operation of more than one Black Start Generating Unit in parallel providing that:

(i) the Black Start Generation supplier demonstrates that the proposed Generation resource shares reactive burden equitably;

(ii) all Participating Generators associated with the proposed Black Start source are located in the same general area.

Buck/boost capability requirement shall be dependent on the location of the proposed resource in relation to Black Start load.

(f) All Black Start Generating Units must have the following communication/control requirements:

(i) dial-up telephone;

(ii) backup radio;

(iii) manning levels which accord with Good Utility Practice.

Appendix E

Submitted Ancillary Services Data Verification

Verification of Submitted Data for Ancillary Services

The CAISO shall use the following procedures for verifying the Bid information submitted by Scheduling Coordinators for Ancillary Services.

1. Bid File and Schedule Format. The CAISO shall verify that the Bids conform to the format specified for the type of Ancillary Service Bid submitted. If the Bid file does not conform to specifications, it shall be annotated by the CAISO to indicate the location of the errors, and returned to the Scheduling Coordinator for corrections. Any changes made by a Scheduling Coordinator shall require a new submittal of Bid information, and all validity checks shall be performed on the re-submitted Bid.

2. Generation Bids.

2.1. Quantity Data. The CAISO shall verify that no Scheduling Coordinator is submitting a Bid quantity for Regulation, Spinning Reserve, or Non-Spinning Reserve which exceeds available capacity for Regulation and Operating Reserves on the Generating Units, Loads and resources scheduled for that Settlement Period.

2.2 Location Data. The CAISO shall verify that the Location data corresponds to the CAISO Controlled Grid Interconnection data.

2.3. Operating Capability. The CAISO shall verify that the operating capability data corresponds to the CAISO Controlled Grid Interconnection data for each Generating Unit, Load or other resource for which a Scheduling Coordinator is submitting an Ancillary Service Bid.

3. [Not Used]

4. Notification of Validity or Invalidity of Ancillary Services Bids. The CAISO shall, as soon as reasonably practical following the receipt of competitive Bids or Self-Provided Ancillary Service Self-Schedules, send to the Scheduling Coordinator who submitted the Bid the following information:

(a) acknowledgment of receipt of the competitive Bid or Self-Provided Ancillary Service Self-Schedule;

(b) notification that the Bid has been accepted or rejected for non-compliance with the rules specified in this Appendix. If a Bid is rejected, such notification shall contain an explanation of why the Bid was not accepted;

(c) a copy of the Bid or Self-Schedule as processed by the CAISO.

In response to an invalid Bid, the Scheduling Coordinator shall be given a period of time to respond to the notification. The Scheduling Coordinator shall respond by resubmitting a corrected Bid. If the Scheduling Coordinator does not respond to the notification within the required time frame, the CAISO shall proceed without that Scheduling Coordinator’s Bid.

5. Treatment of Missing Values.

5.1 Missing Location Values. Any Bid submitted without a Location Code shall be deemed to have a zero Bid quantity for that Settlement Period.

5.2 Missing Quantity Values. Any Bid submitted without a quantity value shall be deemed to have a zero Bid quantity for Ancillary Service capacity for that Settlement Period.

5.3 Missing Price Values. Any Bid submitted with non-zero quantity value, but with a missing price value, shall be rejected.

6. Treatment of Equal Price Bids. The CAISO shall allow these Scheduling Coordinators to resubmit, at their own discretion, their Bid no later than two (2) hours the same day the original Bid was submitted. In the event identical prices still exist following resubmission of Bids, the CAISO shall determine the merit order for each Ancillary Service by considering applicable constraint information for each Generating Unit, Load or other resource, and optimize overall costs for the Trading Day. If equal Bids still remain, the CAISO shall proportion participation in the Day-Ahead Schedule or HASP Schedule (as the case may be) amongst the bidding Generating Units, Loads and resources with identical Bids to the extent permitted by operating constraints and in a manner deemed appropriate by the CAISO.

7. Receipt of Bids. The CAISO shall maintain an audit trail relating to the receipt of Bids and the processing of those Bids.

Appendix F Rate Schedules

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, (8) the Settlements, Metering, and Client Relations Charge, and (9) the Virtual Award Change.

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. 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 a non-zero invoice value where the non-zero value reflects market activity in the current Trading Month.

9. The rate in $/MWh for the Virtual Award 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 virtual supply and virtual demand cleared in the IFM. This service category will be allocated nine (9) percent of the Forward Scheduling Charge and Market Usage – Forward Energy service categories based upon the total annual forecasted cleared supply and demand. All amounts collected from the assessment of the Virtual Bid Submission Charge in a given year will be used to offset the amount of the Virtual Award Charge for the next year.

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.

Part C – Costs Recovered through the GMC

As provided in Section 11.22.2 of the CAISO Tariff, the Grid Management Charge includes the following costs, as projected in the CAISO's budget for the year to which the Grid Management Charge applies:

- CAISO Operating Costs;
- CAISO Other Costs and Revenues, including penalties, interest earnings and other revenues;
- CAISO Financing Costs, including debt service on CAISO Start Up and Development Costs and subsequent capital expenditures; and
- CAISO Operating and Capital Reserves Costs.

Such costs, for the CAISO as a whole, are allocated to the service charges that comprise the Grid Management Charge: (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) Core Reliability Services/ Energy Transmission Services – Transmission Ownership Rights Charge, (6) Forward Scheduling Charge, (7) Market Usage Charge, (8) Settlements, Metering, and Client Relations Charge, and (9) Virtual Award 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 CAISO Operating and Capital Reserves Account, 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 five percent (5%) or $1 million, whichever is greater, from the estimated revenue collections provided in the annual informational filing.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

CAISO Operating Costs + CAISO Financing Costs + CAISO Other Costs and Revenues + CAISO Operating and Capital Reserves Costs,

[The "USoA" reference below is the FERC Uniform System of Accounts, and is intended to include subsequent re-numbering or re-designation of the same accounts or subaccounts.]

Where,

(1) CAISO Operating Costs include:

(a) Transmission expenses (USoA 560-574);

(b) Regional market expenses (USoA 575 subaccounts);

(c) Customer accounting expenses (USoA 901-905);

(d) Customer service and informational expenses (USoA 906-910);

(e) Sales expenses (USoA 911-917);

(f) Administrative & general expenses (USoA 920-935);

(g) Taxes other than income taxes that relate to CAISO operating income (USoA 408.1); and

(h) Miscellaneous, non-operating expenses, penalties and other deductions (USoA 426 subaccounts).

(2) CAISO Financing Costs include:

(a) 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 CAISO notes. This amount includes the current year accrued principal and interest payments due in the first one hundred twenty (120) days of the following year.

(b) The debt service coverage requirement, which is a percentage of the senior lien debt service, i.e., all debt service that has a first lien on CAISO net operating revenues. The coverage requirement is twenty-five percent (25%), unless otherwise specified by the rate covenants of the official statements for each CAISO bond offering.

(3) CAISO Other Costs and Revenues include:

(a) Interest earnings (USoA 419) on CAISO Operating and Capital Reserves Account balances, excluding interest on bond or note proceeds specifically designated for capital projects or capitalized interest.

(b) Miscellaneous revenues (USoA 421 and 456 subaccounts), including but not limited to Scheduling Coordinator application and training fees, and fines assessed and collected by the CAISO.

(c) Other interest expenses (USoA 431) not provided for elsewhere.

(4) CAISO Operating and Capital Reserves Costs include:

(a) The projected CAISO Operating and Capital Reserves Account balance for December 31 of the prior year less the reserve requirement. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. The reserve requirement is fifteen percent (15%) of annual CAISO Operating Costs, unless otherwise specified by (1) the rate covenants of the official statements for each CAISO bond offering, (2) the CAISO Governing Board or (3) the FERC.

(b) Funding from current year revenues for approved capital and projects initiated in the fiscal year.

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

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

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, 2012. 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.

The allocation of costs to cost allocation factors FS and MU-FE includes the allocation of costs to the Virtual Award 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.

Table 1
O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
2111	CEO-General	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2121	Market Monitoring	22.40%	0.00%	0.00%	6.20%	46.69%	17.11%	7.60%	100.00%
2122	Market Surveillance Committee (Non-labor costs only)	25.00%	0.00%	0.00%	0.00%	75.00%	0.00%	0.00%	100.00%
2211	Planning and Infrastructure Development	53.25%	46.75%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2221	Regional Transmission-North	57.67%	42.33%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2231	Regional Transmission-South	54.60%	45.40%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2241	Grid Assets	68.34%	31.66%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2242	Generator Interconnections	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2251	Network Applications	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2311	CFO General	37.33%	14.40%	0.42%	3.96%	10.70%	5.12%	28.05%	100.00%
2321	Accounting	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2331	Financial Planning and Treasury	31.41%	12.20%	0.36%	3.46%	10.76%	2.86%	38.95%	100.00%
2341	Human Resources	40.85%	16.67%	0.47%	3.01%	10.06%	6.00%	22.94%	100.00%

CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
2351	Facilities	40.85%	16.67%	0.47%	3.01%	10.06%	6.00%	22.94%	100.00%
2361	Procurement and Vendor Management	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2371	Enterprise Risk Management	34.73%	11.83%	0.38%	5.53%	9.35%	6.78%	31.40%	100.00%
2372	Internal Audit	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2373	Information Security	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
2374	Physical Security	40.85%	16.67%	0.47%	3.01%	10.06%	6.00%	22.94%	100.00%
CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
2411	Information Technology-General	35.13%	8.03%	0.35%	8.08%	11.07%	4.65%	32.69%	100.00%
2412	Asset Management (Non-Labor costs only)	32.40%	9.79%	0.33%	7.51%	12.78%	5.37%	31.83%	100.00%
2421	IT Projects	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
2431	IT Project Management	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
2441	Software Quality Assurance	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
2451	IT Support & Operations	37.26%	10.02%	0.39%	9.71%	12.49%	2.34%	27.78%	100.00%
2452	System & Database Administration	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
2453	Data Center &	40.24%	18.35%	0.49%	2.44%	14.15%	1.64%	22.70%	100.00%

CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
	Operations								
2454	Architecture & Systems Engineering	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
2462	EMS Information Technology	94.09%	2.45%	0.80%	0.00%	1.33%	0.00%	1.33%	100.00%
2463	Operations Information Technology	31.43%	9.40%	0.33%	13.67%	26.52%	0.00%	18.65%	100.00%
2464	Corporate Systems	32.52%	10.30%	0.32%	1.22%	10.23%	1.92%	43.49%	100.00%

CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
2511	Operations-General	46.52%	16.54%	0.75%	1.33%	15.19%	2.09%	17.58%	100.00%
2521	Grid Operations	68.53%	24.09%	1.42%	0.00%	5.96%	0.00%	0.00%	100.00%
2522	Real-Time Operations	60.99%	29.70%	1.20%	0.00%	8.11%	0.00%	0.00%	100.00%
2523	Scheduling	65.75%	32.87%	1.38%	0.00%	0.00%	0.00%	0.00%	100.00%
2524	Outage Management	94.00%	0.37%	4.17%	0.00%	1.47%	0.00%	0.00%	100.00%
2531	Alhambra Grid Operations	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2541	Market Services	5.38%	0.00%	0.00%	5.02%	44.24%	7.90%	37.46%	100.00%
2542	Market Operations	5.14%	0.00%	0.00%	13.08%	56.08%	20.56%	5.14%	100.00%
2543	Billing and Settlements	12.56%	0.00%	0.00%	0.00%	0.00%	0.00%	87.44%	100.00%
2544	Settlement Projects	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
2545	Market Information	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%
2551	Operations Support	38.68%	19.64%	0.00%	0.00%	1.76%	0.00%	39.92%	100.00%
2552	Operations Data and Compliance	41.75%	0.00%	0.00%	0.00%	0.00%	0.00%	58.25%	100.00%
2553	Operations Procedures and Training	63.23%	36.77%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2554	Model & Contract Implementation	35.54%	0.00%	0.00%	0.00%	8.77%	0.00%	55.69%	100.00%

2555	Information Engineering & Analysis	8.80%	46.39%	0.00%	0.00%	0.00%	0.00%	44.82%	100.00%
2561	Reliability Coordination	100.00 %	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
2611	General Counsel-General	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2621	Asst General Counsel-Corporate	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2631	Asst General Counsel-Regulatory	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2641	Asst General Counsel Tariff & Compliance	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2651	Asst Corporate Secretary	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2711	Market Development-Program Mgmt-General	18.92%	21.45%	0.04%	8.86%	42.78%	0.43%	7.51%	100.00%
2721	Market and Product Development	7.43%	14.86%	0.00%	7.43%	62.86%	0.00%	7.43%	100.00%
2722	Tariff and Regulatory/ Policy Development	0.00%	9.34%	0.00%	18.69%	71.97%	0.00%	0.00%	100.00%
2723	Infrastructure Policy & Contracts	45.42%	44.49%	0.00%	0.00%	0.00%	0.00%	10.09%	100.00%
2731	Program Office	38.89%	15.11%	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2741	MRTU Program	10.30%	4.25%	0.12%	19.93%	10.75%	16.19%	38.46%	100.00%

CC#	Cost Center Name	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
2811	External Affairs-General	12.89%	5.00%	0.15%	1.42%	4.41%	1.17%	74.96%	100.00%
2821	Communications & Public Relations	38.89%	15.11 %	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2822	Information Products & Services	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
2831	State/Federal Affairs	38.89%	15.11 %	0.44%	4.29%	13.32%	3.54%	24.42%	100.00%
2841	Customer Services and Industry Affairs	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%

Financing and Capital Project Budgets								
	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
1998/2000 Bond Financed Capital	29.96%	8.36%	0.31%	11.78 %	16.47%	1.07%	32.05%	100.00%
2004 Bond Financed Capital	16.20%	5.07%	0.17%	17.67 %	10.90%	14.09%	35.90%	100.00%
2007 Bond Financed Capital	13.44%	5.08%	0.15%	19.05 %	10.48%	15.71%	36.09%	100.00%

Other Revenues and Expense Credits								
SC Application and Training Fees	0.00%	0.00%	0.00%	0.00 %	0.00%	0.00%	100.00 %	100.00%
WECC Reimbursement/NERC Reimbursement	100.00 %	0.00%	0.00%	0.00 %	0.00%	0.00%	0.00%	100.00%
COI Path Operator Fee	71.81%	28.19%	0.00%	0.00 %	0.00%	0.00%	0.00%	100.00%
Large Generator Interconnection Project	100.00 %	0.00%	0.00%	0.00 %	0.00%	0.00%	0.00%	100.00%
Interest Earnings	34.78%	12.18%	0.38%	7.33 %	12.98 %	5.30%	27.06%	100.00%

Table 2

Capital Cost Allocation Factors

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
ACC Upgrades (Communication between ISO & IOUs)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Ancillary Services	14.88%	0.00%	0.12%	40.00%	45.00%	0.00%	0.00%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Management (ASM) Component of SA								
Application Development Tools	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Automated Dispatch System (ADS)	49.59%	0.00%	0.41%	25.00%	20.00%	0.00%	5.00%	100.00%
Automated Load Forecast System (ALFS)	69.42%	0.00%	0.58%	10.00%	20.00%	0.00%	0.00%	100.00%
Automatic Mitigation Procedure (AMP)	0.00%	84.30%	0.70%	0.00%	15.00%	0.00%	0.00%	100.00%
Backup systems (Legato/Quantum)	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Balance of Business Systems (BBS)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Balancing Energy Ex Post Price (BEEP) Component of SA	49.59%	2.83%	0.43%	20.00%	27.14%	0.00%	0.00%	100.00%
Bill's Interchange Schedule (BITS)	84.30%	0.00%	0.70%	0.00%	15.00%	0.00%	0.00%	100.00%
CAISO Outage Modeling Tool (COMT)	64.47%	1.42%	0.55%	15.00%	18.57%	0.00%	0.00%	100.00%
CaseWise (process modeling tool)	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
CHASE	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Client Relations Tools	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Common Information Model (CIM)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Compliance	41.75%	0.00%	0.00%	0.00%	0.00%	0.00%	58.25%	100.00%
Congestion Management (CONG) Component of SA	0.00%	28.34%	0.23%	0.00%	71.43%	0.00%	0.00%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Congestion Reform-DSOW	0.00%	63.76%	0.53%	0.00%	35.71%	0.00%	0.00%	100.00%
Congestion Revenue Rights (CRR)	0.00%	22.67%	0.19%	0.00%	77.14%	0.00%	0.00%	100.00%
DataWarehouse	31.59%	2.86%	0.00%	3.07%	18.90%	6.93%	36.65%	100.00%
Dept. of Market Analysis Tools (SAS/MARS)	22.40%	0.00%	0.00%	6.20%	46.69%	17.11%	7.60%	100.00%
Dispute Tracking System (Remedy)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Documentum	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Electronic Tagging (Etag)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Energy Management System (EMS)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Engineering Analysis Tools	59.51%	39.67%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Evaluation of Market Separation	0.00%	14.17%	0.12%	0.00%	85.71%	0.00%	0.00%	100.00%
Existing Transmission Contracts Calculator (ETCC)	24.79%	4.25%	0.24%	20.00%	30.71%	0.00%	20.00%	100.00%
FERC Study Software	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%
Firm Transmission Right (FTR) and Secondary	0.00%	17.00%	0.14%	15.00%	57.86%	0.00%	10.00%	100.00%

Registration System (SRS)								
Global Resource Reliability Management Application (GRRMA)	74.38%	14.88%	0.74%	0.00%	10.00%	0.00%	0.00%	100.00%
Grid Operations Training Simulator (GOTS)	62.48%	36.70%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.00%
Human Resources	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
IBM Contract (also known as Outsourced Contracts)	34.79%	13.90%	0.40%	4.29%	11.66%	4.26%	30.69%	100.00%
Integrated Forward Market (IFM)	9.92%	0.00%	0.08%	35.00%	0.00%	55.00%	0.00%	100.00%
Internal Development	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Interzonal Congestion Management reform - Real Time	0.00%	63.76%	0.53%	0.00%	35.71%	0.00%	0.00%	100.00%
Land and Building Costs	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Local Area Network (LAN)	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Locational Marginal Pricing (LMPM)	9.92%	0.00%	0.08%	35.00%	55.00%	0.00%	0.00%	100.00%
Market Quality System (MQS)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Masterfile	19.84%	0.00%	0.16%	20.00%	55.00%	0.00%	5.00%	100.00%
Meter Data Acquisition System (MDAS)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Miscellaneous (2004 related capital)	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Monitoring (Tivoli)	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
MRTU Capital	12.68%	4.68%	0.14%	19.01%	10.75%	15.41%	37.33%	100.00%
Network Applications	0.00%	99.18%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
New Resource Interconnection (NRI)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
New System Equipment (replacement of owned equipment)	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
NT/web servers	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
NT-servers	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Office Automation - desktop/laptop (OA)	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Office equipment (scanner, printer, copier, fax, Communication Equip.)	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Open Access Same-Time Information System (OASIS)	9.92%	2.83%	0.11%	25.00%	42.14%	0.00%	20.00%	100.00%
Operational Meter Analysis and Reporting (OMAR)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Oracle Corporate Financials	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Oracle Enterprise Manager (OEM)	6.46%	0.68%	0.06%	43.90%	26.52%	0.00%	22.38%	100.00%
Oracle Licenses	6.46%	0.68%	0.06%	43.90%	26.52%	0.00%	22.38%	100.00%
Oracle Market Financials BBS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Out of Sequence Market Operation Settlements Information System (OOS)	4.96%	4.96%	0.08%	0.00%	90.00%	0.00%	0.00%	100.00%
Outage Scheduler (OS)	49.59%	5.67%	0.46%	10.00%	34.29%	0.00%	0.00%	100.00%
Participating Intermittent Resource Project (PIRP)	0.00%	0.00%	0.00%	64.75%	35.25%	0.00%	0.00%	100.00%
Physical Facilities Software Application/Furniture/Leasehold Improvements	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Portal	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Post Transaction Repository (PTR)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Process Information System (PI)	79.34%	0.00%	0.66%	0.00%	10.00%	0.00%	10.00%	100.00%
Rational Buyer	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Real Time Energy Dispatch System (REDS)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%

Real Time Nodal Market	34.71%	0.00%	0.29%	10.00%	55.00%	0.00%	0.00%	100.00%
Reliability Management System (RMS)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Remedy (related to Transmission Registry, New Resource Interconnection and Resource Registry)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Resource Adequacy	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Resource Register (RR)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
RMR Application Validation Engine (RAVE)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Scheduling & Logging for ISO California (SLIC)	64.47%	1.42%	0.55%	15.00%	18.57%	0.00%	0.00%	100.00%
Scheduling & Tagging Next Generation (STiNG)	84.30%	0.00%	0.70%	0.00%	15.00%	0.00%	0.00%	100.00%
Scheduling Architecture (SA)	15.51%	12.00%	0.23%	19.99%	52.27%	0.00%	0.00%	100.00%
Scheduling Infrastructure (SI)	0.00%	0.00%	0.00%	64.75%	35.25%	0.00%	0.00%	100.00%
Scheduling Infrastructure Business Rules (SIBR)	0.00%	0.00%	0.00%	64.75%	35.25%	0.00%	0.00%	100.00%
Security Constrained Economic Dispatch (SCED)	0.00%	39.67%	0.33%	0.00%	60.00%	0.00%	0.00%	100.00%
Security- External/Physical	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Security-ISS (CUDA)	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Settlements and Market Clearing	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%
Sign Board (Symon Board maint.)	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Startup Costs through 3/31/98, Working Capital-3 months	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Storage (EMC symmetrix)	24.87%	6.18%	0.21%	13.62%	17.62%	4.11%	33.40%	100.00%

System Equipment Buyouts (lease buyouts)	44.00%	1.00%	0.00%	7.00%	11.00%	0.00%	37.00%	100.00%
Tactical Emergency Management System (TEMS)	99.18%	0.00%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%

System	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Telephone/PBX	40.34%	19.26%	0.49%	1.52%	14.24%	1.70%	22.45%	100.00%
Training Systems	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation	0.00%	99.18%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Transmission Map Plotting & Display	49.59%	49.59%	0.82%	0.00%	0.00%	0.00%	0.00%	100.00%
Treasury Workstation/Investment Program	40.21%	19.26%	0.49%	1.81%	15.60%	2.00%	20.62%	100.00%
Trustee Costs, Interest-Capitalized, User Groups	17.40%	2.96%	0.17%	17.81%	19.94%	0.03%	41.69%	100.00%
Utilities - System i.e. Print drivers	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Vitria (Middleware)	23.53%	3.01%	0.22%	9.91%	6.42%	9.47%	47.44%	100.00%
Wide Area Network (WAN)	38.26%	0.93%	0.32%	19.89%	12.46%	0.63%	27.51%	100.00%

Table 3

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

	CRS	ETS	CRS/ETS TOR	FS	MU	MU-FE	SMCR	Total
Functional Association of Settlements, Metering, and Client Relations	0.00%	65.68%	0.25%	0.70%	23.73%	9.64%	0.00	100.00

Part F –[Not Used]

Schedule 2
[Not Used]

Schedule 3
High Voltage Access Charge and Wheeling Access Charge

1. Objectives and Definitions.

1.1 Objectives.

(a) The Access Charge will remain utility-specific until a New Participating TO executes the Transmission Control Agreement, at which time the Access Charge will change as discussed below.

(b) The Access Charge is the charge assessed for using the CAISO Controlled Grid. It consists of three components, the High Voltage Access Charge (HVAC), the Transition Charge and the Low Voltage Access Charge (LVAC).

(c) The HVAC ultimately will be based on one CAISO Grid-wide rate. Initially, the HVAC will be based on TAC Areas, which will transition 10% per year to the CAISO Grid-wide rate. In the first year after the TAC Transition Date described in Section 4.2 of this Schedule 3, the HVAC will be a blend based on 10% CAISO Grid-wide and 90% TAC Area. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

(d) New High Voltage Facility additions and capital additions to Existing High Voltage Facilities will be immediately included in the CAISO Grid-wide component of the HVAC. The Transmission Revenue Requirement for New High Voltage Facilities will not be included in the calculation of the Transition Charge.

(e) The LVAC will remain utility-specific and will be determined by each Participating TO. The LVAC of Non-Load-Serving Participating TOs may also be project specific. Each Participating TO will charge for and collect the LVAC, subject to Section 26.1 of the CAISO Tariff and Section 13 of this Schedule 3.

(f) The cost-shift associated with transitioning from utility-specific rates to one CAISO Grid-wide rate will be mitigated in accordance with the CAISO Tariff, including this schedule.

(g) The Wheeling Access Charge is paid by Scheduling Coordinators for Wheeling as set forth in Section 26.1.4 of the CAISO Tariff. The CAISO will collect the Wheeling revenues from Scheduling Coordinators on a Trading Interval basis and repay these to the Participating TOs based on the ratio of each Participating TO's Transmission Revenue Requirement to the sum of all Participating TOs' Transmission Revenue Requirements.

1.2 Definitions

Unless the context otherwise requires, any word or expression defined in the Master Definition Supplement shall have the same meaning where used in this Schedule 3.

2. Assessment of High Voltage Access Charge and Transition Charge.

All UDCs and MSS Operators in a PTO Service Territory serving Gross Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS Operator in a PTO Service Territory shall pay to the CAISO a charge for transmission service on the High Voltage

Transmission Facilities included in the CAISO Controlled Grid. The charge will be based on the High Voltage Access Charge applicable to the TAC Area in which the point of delivery is located and the applicable Transition Charge. A UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3 of the CAISO Tariff. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

3. TAC Areas.

3.1 TAC Areas are based on the Control Areas in California prior to the CAISO Operations Date. Three TAC Areas will be established based on the Original Participating TOs: (1) a Northern Area consisting of the PTO Service Territory of Pacific Gas and Electric Company and the PTO Service Territory of any entity listed in Section 3.3 or 3.5 of this Schedule; (2) an East Central Area consisting of the PTO Service Territory of Southern California Edison Company and the PTO Service Territory of any entity listed in Section 3.4, 3.5 or 3.6 (as indicated therein) of this Schedule 3; and (3) a Southern Area consisting of the PTO Service Territory of San Diego Gas & Electric Company. Participating TOs that are not in one of the above cited PTO Service Territories are addressed below.

3.2 If the Los Angeles Department of Water and Power joins the CAISO and becomes a Participating TO, its PTO Service Territory will form a fourth TAC Area, the West Central Area.

3.3 If any of the following entities becomes a Participating TO, its PTO Service Territory will become part of the Northern Area: Sacramento Municipal Utility District, Western Area Power Administration - Sierra Nevada Region, the Department of Energy California Labs, Northern California Power Agency, City of Redding, Silicon Valley Power, City of Palo Alto, City and County of San Francisco, Alameda Bureau of Electricity, City of Biggs, City of Gridley, City of Healdsburg, City of Lodi, City of Lompoc Utility Department, Modesto Irrigation District, Turlock Irrigation District, Plumas County Water Agency, City of Roseville Electric Department, City of Shasta Lake, and City of Ukiah or any other entity owning or having contractual rights to High Voltage or Low Voltage Transmission Facilities in Pacific Gas and Electric Company's Control Area prior to the CAISO Operations Date.

3.4 If any of the following entities becomes a Participating TO, its PTO Service Territory will become part of the East Central Area: City of Anaheim Public Utility Department, City of Riverside Public Utility Department, City of Azusa Light and Water, City of Banning Electric, City of Colton, City of Pasadena Water and Power Department, The Metropolitan Water District of Southern California and City of Vernon or any other entity owning or having contractual rights to High Voltage or Low Voltage Transmission Facilities in Southern California Edison Company's Control Area prior to the CAISO Operations Date.

3.5 If the California Department of Water Resources becomes a Participating TO, its High Voltage Transmission Revenue Requirements associated with High Voltage Transmission Facilities in the Northern Area would become part of the High Voltage Transmission Revenue Requirement for the Northern Area while the remainder would be included in the East Central Area.

3.6 If the City of Burbank Public Service Department (Burbank) and/or the City of Glendale Public Service Department (Glendale) become Participating TOs after or at the same time as the Los Angeles Department of Water and Power becomes a Participating TO, then the PTO Service Territory of Burbank and/or Glendale would become part of the West Central Area. Otherwise, if Burbank or Glendale becomes a Participating TO, prior to Los Angeles, its PTO Service Territory will become part of the East Central Area. Once either Burbank or Glendale are part of the East Central Area, they will not move to the West Central Area if such area is established.

3.7 If the Imperial Irrigation District or an entity outside the State of California should apply to become a Participating TO, the CAISO Governing Board will review the reasonableness of integrating the entity into one of the existing TAC Areas. If the entity cannot be integrated without the potential for significant cost shifts, the CAISO Governing Board may establish a separate TAC Area.

4. TAC Transition Date.

4.1 New Participating TOs shall provide the CAISO with a notice of intent to join and execute the Transmission Control Agreement by either January 1 or July 1 of any year and provide the CAISO with an application within 15 days of such notice of intent.

4.2 The TAC Transition Period shall begin on either January 1 or July 1 after the date the first New Participating TO's execution of the Transmission Control Agreement takes effect (TAC Transition Date). The TAC Transition Date shall be the same for the Northern Area, East Central Area and the Southern Area. The TAC Transition Date shall also be the same for the West Central Area, should it come into existence in accordance with Section 3.2 of this Schedule 3, unless the CAISO provides additional information demonstrating the need for a deferral. The 10-year TAC Transition Period described in Section 5.8 of Schedule 3 shall start from that date. If the West Central TAC Area is created after the TAC Transition Date, the applicable High Voltage Access Charge shall transition to a CAISO Grid-wide High Voltage Access Charge over the TAC Transition Period remaining from the TAC Transition Date, on the same schedule as the other TAC Areas.

4.3 Application to Additional TAC Areas. For any TAC Areas other than those specified in Section 4.2 of this Schedule 3, created after the TAC Transition Date, including any TAC Area created as a result of the application of Section 3.7 of this Schedule 3, whether and over what period the applicable High Voltage Access Charge shall transition to a CAISO Grid-wide charge shall be determined by the CAISO Governing Board.

4.4 Application to Wheeling Access Charges. The transition described in this Section 4 shall also apply, on the same schedule, to High Voltage Wheeling Access Charges.

4.5 Conversion of Existing Rights. During the process by which a New Participating TO executes the Transmission Control Agreement, the CAISO and potential New Participating TO that has an obligation to serve Load shall determine the IFM Congestion Credit to be allocated to the New Participating TO in accordance with Section 4.3.1.2 of the CAISO Tariff for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the CAISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted transmission capacity.

5. Determination of the Access Charge.

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and a CAISO Grid-wide component, a Transition Charge, and a Low Voltage Access Charge (LVAC) that is based on a utility-specific rate established by each Participating TO in accordance with its TO Tariff. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

5.2 Each Participating TO will develop, in accordance with Section 6 of this Schedule 3, a High Voltage Transmission Revenue Requirement ($HVTRR_{PTO}$) consisting of a Transmission Revenue Requirement for Existing High Voltage Facility ($EHVTRR_{PTO}$) and a Transmission Revenue Requirement for New High Voltage Facility ($NHVTRR_{PTO}$). The $HVTRR_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3. At the conclusion of the 10-year TAC

Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate. Accordingly, the requirement for each Participating TO to divide its HVTRR into new and existing components shall cease to apply.

5.3 The Gross Load amount in MWh shall be established by each Participating TO and filed at FERC with each Participating TO's Transmission Revenue Requirement (GL_{PTO}).

5.4 The HVAC applicable to each UDC or MSS Operator serving Gross Load in the PTO Service Territory, shall be based on a TAC Area component ($HVAC_A$) and a CAISO Grid-wide component ($HVAC_I$).

$$HVAC = HVAC_A + HVAC_I$$

5.5 The Existing Transmission Revenue Requirement for the TAC Area component ($ETRR_A$) is the summation of each Participating TO's $EHVTRR_{PTO}$ in that TAC Area. The Gross Load in the TAC Area (GL_A) is the summation of each Participating TO's Gross Load in that TAC Area (GL_{PTO}). The TAC Area component will be based on the product of Existing Transmission Revenue Requirement for the TAC Area ($ETRR_A$) and the applicable annual transition percentage (%TA) in Section 5.8 of this Schedule 3, divided by the Gross Load in the TAC Area (GL_A).

$$ETRR_A = \Sigma\ EHVTRR_{PTO}$$

$$GL_A = \Sigma\ GL_{PTO}$$

$$HVAC_A = (ETRR_A * \%TA) / GL_A$$

5.6 The Existing Transmission Revenue Requirement for the CAISO Grid-wide component ($ETRR_I$) will be the summation of all TAC Areas' $ETRR_A$ multiplied by the applicable annual transition percentage (%IGW) in Section 5.8 of this Schedule 3. The New Transmission Revenue Requirement (NTRR) is the summation of each Participating TO's $NHVTRR_{PTO}$. The CAISO Grid-wide component will be based on the $ETRR_I$ plus the NTRR, divided by the summation of all Gross Loads in the TAC Areas (GL_A).

$$ETRRI = \Sigma\ ETRR_A * \%IGW$$

$$HVAC_I = (ETRR_I + NTRR) / \Sigma\ GL_A$$

The foregoing formulas will be adjusted, as necessary to take account of new TAC Areas.

5.7 The Transition Charge shall be calculated separately for each Participating TO by dividing (i) the net difference between (1) the Participating TO's payment responsibility, if any, under Section 26.5 of the CAISO Tariff and Section 7 of this Schedule 3; and (2) the amount, if any, payable to the Participating TO in accordance with Section 26.5 of the CAISO Tariff and Section 7 of this Schedule 3; by (ii) the total of all forecasted Gross Load in the PTO Service Territory of the Participating TO, including the UDC and/or MSS Operator. If greater than zero, the Transition Charge shall be collected with the High Voltage Access Charge. If less than zero, the Transition Charge shall be credited with the High Voltage Access Charge. The amount of each Participating TO's NHVTRR shall not be included in the Transition Charge calculation.

5.8 The High Voltage Access Charge shall transition over a 10-year TAC Transition Period from TAC Area to CAISO Grid-wide. The transition percentage to be used for each year will be based on the following:

Year	TAC Area High Voltage (%TA)	CAISO Grid-Wide High Voltage (%IGW)
1	90%	10%
2	80%	20%
3	70%	30%
4	60%	40%
5	50%	50%
6	40%	60%
7	30%	70%
8	20%	80%
9	10%	90%
10	0%	100%

5.9 After the completion of the TAC Transition Period described in Section 4 of this Schedule 3, the High Voltage Access Charge shall be equal to the sum of the High Voltage Transmission Revenue Requirements of all Participating TOs, divided by the sum of the Gross Loads of all Participating TOs, and the provisions of this Section 5 of this Schedule 3 referring to the calculation and application of the TAC Transition Charge shall cease to apply.

6. High Voltage Transmission Revenue Requirement.

6.1 The High Voltage Transmission Revenue Requirement of a Participating TO will be determined consistent with CAISO procedures posted on the CAISO Website and shall be the sum of:

(a) the Participating TO's High Voltage Transmission Revenue Requirement (including costs related to Existing Contracts associated with transmission by others and deducting transmission revenues actually expected to be received by the Participating TO related to transmission for others in accordance with Existing Contracts, less the sum of the Standby Transmission Revenues); and

(b) the annual high voltage TRBA adjustment, which shall be based on the principal balance in the high voltage TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. A Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual High Voltage Transmission Revenue Requirement in its high voltage TRBA. If the annual high voltage TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's High Voltage Transmission Revenue Requirement by the number of days the High Voltage Transmission Facilities were under the CAISO's Operational Control divided by the number of days in the year.

7. Limitation.

(a) During each year of the TAC Transition Period described in this Schedule 3, the increase in the total payment responsibility applicable to Gross Loads in the PTO Service Territory of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 26.5 of the CAISO Tariff; plus (ii) the amount applicable to the implementation of the High Voltage Access Charge shall not exceed the amount specified in paragraph (b) of this section. This limitation shall be calculated individually for each Original Participating TO, provided that, if the net effect of clauses (i) and (ii) of this paragraph is positive for one or more Original Participating TOs for any year, the combined net effect shall be allocated among all Original Participating TOs in proportion to the amounts specified in paragraph (b) of this section. This limitation shall be applied by the CAISO's calculation annually of amounts payable by New Participating TOs to Original Participating TOs such that the combined effect of clauses (i) and (ii) of this paragraph, and the payments received by each Original Participating TO shall not exceed the amounts specified in paragraph (b) of this section. The amount receivable by the Original Participating TO from the New Participating TOs to implement the limitation in paragraph (b) of this section, shall be credited through the Transition Charge established pursuant to Section 5.7 of this Schedule 3. Payment responsibility under this section, if any, shall be allocated among New Participating TOs in proportion to their TAC Benefits. At the conclusion of the ten-year TAC Transition Period, the Transition Charge and the obligations set forth in this Section 7 of this Schedule 3 will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

(b) The maximum annual amounts for Original Participating TO shall be as follows:

(i) For Pacific Gas and Electric Company and Southern California Edison Company, the maximum annual amount shall be thirty-two million dollars ($32,000,000.00) each; and

(ii) For San Diego Gas & Electric Company, the maximum annual amount shall be eight million dollars ($8,000,000.00).

8. Updates to High Voltage Access Charges.

8.1 High Voltage Access Charges and High Voltage Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the High Voltage Transmission Revenue Requirements of any Participating TO. Using the High Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO, the CAISO will recalculate on a monthly basis the High Voltage Access Charge and Transition Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on

January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

8.2 For service provided by a Participating TO prior to the TAC Transition Date, no refund ordered by FERC or amount accrued to that Participating TO's Transmission Revenue Balancing Account related to such service shall be reflected in the High Voltage Access Charge, Low Voltage Access Charge, the High Voltage Transmission Revenue Requirement, or the Low Voltage Transmission Revenue Requirement of a Participating TO. For service provided by a Participating TO following the TAC Transition Date, any refund associated with a Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced in the CAISO Market Invoice.

8.3 If the Participating TO withdraws one or more of its transmission facilities from the CAISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the CAISO will no longer collect the TRR for that transmission facility through the CAISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the CAISO. The withdrawing Participating TO shall be obligated to provide the CAISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at FERC to revise its TRR. The CAISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from CAISO Operational Control.

9. Approval of Updated High Voltage Revenue Requirements.

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the CAISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

9.2 Federal power marketing agencies whose transmission facilities are under CAISO Operational Control shall develop their High Voltage Transmission Revenue Requirements pursuant to applicable federal laws and regulations, including filing with FERC. All such filings with FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The procedures for public participation in a federal power marketing agency's ratemaking process shall be posted on the federal power marketing agency's website. The federal power marketing agency shall also post on the website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's High Voltage Transmission Revenue Requirement. The Participating TO will provide a copy of its filing to the CAISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

10. Disbursement of High Voltage Access Charge and Transition Charge Revenues.

10.1 High Voltage Access Charge and Transition Charge revenues shall be calculated for disbursement to each Participating TO on a monthly basis as follows:

(a) the amount determined in accordance with Section 26.1.2 of the CAISO Tariff ("Billed HVAC/TC");

(b)

(i) for a Participating TO that is a UDC or MSS Operator and has Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the amount each UDC or MSS Operator would have paid and the Participating TO would have received by multiplying the High Voltage Utility-Specific Rates for the Participating TO whose High Voltage Facilities served such UDC and MSS Operator times the actual Gross Load of such UDCs and MSS Operators ("Utility-specific HVAC"); or

(ii) for a Non-Load-Serving Participating TO, then calculate the Non-Load-Serving Participating TO's portion of the total Billed HVAC/TC in subsection (a) based on the ratio of the Non-Load-Serving Participating TO's High Voltage Transmission Revenue Requirement to the sum of all Participating TOs' High Voltage Revenue Requirements.

(c) if the total Billed HVAC/TC in subsection (a) received by the CAISO less the total dollar amounts calculated in Utility-specific HVAC in subsection (b)(i) and subsection (b)(ii) is different from zero, the CAISO shall allocate the positive or negative difference among those Participating TOs that are subject to the calculations in subsection (b)(i) based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all of those Participating TOs' High Voltage Transmission Revenue Requirements that are subject to the calculations in subsection (b)(i). This monthly distribution amount is the "HVAC Revenue Adjustment";

(d) the sum of the HVAC revenue share determined in subsection (b) and the HVAC Revenue Adjustment in subsection (c) will be the monthly disbursement to the Participating TO.

10.2 If the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount billed by the CAISO will be the charges payable by the UDC or MSS Operator in accordance with Section 26.1.2 of the CAISO Tariff less the disbursement determined in accordance with Section 10.1(d) of this Schedule 3. If this difference is negative, that amount will be paid by the CAISO to the Participating TO.

11. Determination of Transmission Revenue Requirement Allocation Between High Voltage and Low Voltage Transmission Facilities.

11.1 Each Participating TO shall allocate its Transmission Revenue Requirement between the High Voltage Transmission Revenue Requirement and Low Voltage Transmission Revenue Requirement based on the Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges contained in Section 12 of this Schedule.

12. Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges.

12.1 Division of Costs:

(a) Substations
Costs for substations and substation equipment, including transformers:

(i) If the Participating TO has substation TRR information by facility and voltage, then the TRR for facilities and equipment at or above 200 kV should be allocated to the HVTRR and the TRR for facilities and equipment below 200 kV should be allocated to the LVTRR;

(ii) If the Participating TO has substation TRR information by facility but not by voltage, then the TRR for facilities and equipment should be allocated to the

HVTRR and to the LVTRR based on the ratio of gross substation investment allocated to HVTRR to gross substation investment allocated to LVTRR pursuant to Section 12.1(a)(i); or

(iii) If the Participating TO does not have substation TRR information by facility or voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the Participating TO's transmission system-wide gross plant ratio. The system-wide gross plant ratio is determined once the costs that can be split between High Voltage Transmission Facilities and Low Voltage Transmission Facilities for all facilities has been developed in accordance with Sections 12.1(a) through (c), then the resulting cost ratio between High Voltage Transmission Facilities and Low Voltage Transmission Facilities shall be used as the system-wide gross plant ratio.

(iv) Costs of transformers that step down from high voltage (200 kV or above) to low voltage, to the extent the Participating TO does not have the revenue requirement information available on a voltage basis, should be allocated consistent with the procedures for substations addressed above.

(b) Transmission Towers and Land with Circuits on Multiple Voltages

For transmission towers that have both High Voltage Transmission Facilities and Low Voltage Transmission Facilities on the same tower, the cost of these assets should be allocated two-thirds to the HVTRR and one-third to the LVTRR. If the transmission tower has only High Voltage Transmission Facilities, then the costs of these assets should be allocated entirely to the HVTRR. If the transmission tower has only Low Voltage Transmission Facilities, then the TRR of these assets should be allocated entirely to the LVTRR. Provided that the Participating TO does not have land cost information available on a voltage basis, in which case the costs should be allocated based on the bright-line of the voltage levels, the costs for land used for transmission rights-of-way for towers that have both high voltage and low voltage wires should be allocated two-thirds to the HVTRR component and one-third to the LVTRR.

(c) Operation and Maintenance, Transmission Wages & Salaries, Taxes, Depreciation and Amortization, and Capital Costs

If the Participating TO can delineate costs for transmission operations and maintenance (O&M), transmission wages and salaries, taxes, depreciation and amortization, or capital costs on a voltage basis, the costs shall be applied on a bright-line voltage basis. If the costs for O&M, transmission wages and salaries, taxes, depreciation and amortization, or capital costs, are not available on voltage levels, the allocation to the HVTRR and the LVTRR should be based on the Participating TO's system-wide gross plant ratio defined in Section 12.1(a).

(d) Existing Transmission Contracts

If the Take-Out Point for the Existing Contract is a High Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR of the Participating TO receiving such revenue. Similarly, the Participating TO that is paying charges under such an Existing Contract may include the costs in its HVTRR. If the Take-Out Point for the Existing Contract is a Low Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR and the LVTRR of the receiving Participating TO based on the ratio of the Participating TO's HVTRR to its LVTRR, prior to any adjustments for such revenues. The Participating TO that is paying the charges under the Existing Contract will include the costs in its HVTRR and LVTRR in the same ratio as the revenues are recognized by the Participating TO receiving the payments.

(e) Division of the TRBA Adjustment between HVTRR and LVTRR

(i) Wheeling revenues associated with transactions exiting the CAISO Controlled Grid at Scheduling Points or Take-Out Points that are at High Voltage Transmission Facilities shall be reflected as high voltage TRBA adjustment components;

(ii) Wheeling revenues associated with transactions exiting the CAISO Controlled Grid at Scheduling Points or Take-Out Points that are at Low Voltage Transmission Facilities shall be attributed between high voltage and low voltage TRBA adjustment components based on the High Voltage and Low Voltage Wheeling Access Charge rates assessed to such transactions by the CAISO and/or the Participating TO;

(iii) Any Low Voltage Access Charge amounts paid pursuant to Section 26.1 of the CAISO Tariff for the Low Voltage Transmission Facilities of a Non-Load-Serving Participating TO shall be reflected as a component of the low voltage TRBA adjustment associated with the Low Voltage Access Charge;

(iv) CRR revenues from CRRs allocated to Participating TOs shall be assigned to high voltage or low voltage TRBA adjustment components based on the voltage of the path related to the CRR; and,

(v) Other Transmission Revenue Credits shall be allocated between high voltage and low voltage TRBA adjustment components on a gross plant basis.

13. Low Voltage Access Charge for a Non-Load-Serving Participating TO. Pursuant to Section 26.1 of the CAISO Tariff, the provisions of this Section 13 of this Schedule 3 shall apply to a Non-Load-Serving Participating TO that has Low Voltage Transmission Facilities.

13.1 Low Voltage Transmission Revenue Requirement. The Low Voltage Transmission Revenue Requirement of a Non-Load-Serving Participating TO shall be calculated separately for each individual project that includes one or more Low Voltage Transmission Facilities or shall be calculated for a group of Low Voltage Transmission Facilities if all are part of projects directly connected to the facilities of the same Participating TO(s). The Low Voltage Transmission Revenue Requirement will be determined consistent with CAISO procedures posted on the CAISO Website and shall be the sum of:

(a) the Non-Load-Serving Participating TO’s Low Voltage Transmission Revenue Requirement for the relevant Low Voltage Transmission Facility or group of facilities; and

(b) the annual low voltage TRBA adjustment for the relevant Low Voltage Transmission Facility or group of facilities, which shall be based on the principal balance in the low voltage TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. In accordance with Section 26.1 of the CAISO Tariff, the Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual Low Voltage Transmission Revenue Requirement in its low voltage TRBA. If the annual low voltage TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's Low Voltage Transmission Revenue Requirement by the number of days the Low Voltage Transmission Facilities were under the CAISO's Operational Control divided by the number of days in the year.

13.2 Updates to Low Voltage Access Charges. Unless otherwise agreed by the affected Participating TOs, a Non-Load-Serving Participating TO shall adjust its Low Voltage Access Charges and Low Voltage Wheeling Access Charges (1) when necessary to reflect any new transmission addition directly connecting a Participating TO to the Low Voltage Transmission Facilities of the Non-Load-Serving Participating TO; (2) on the date FERC makes effective a change to the Low Voltage Transmission Revenue Requirement of the Non-Load-Serving Participating TO; and (3) on the date FERC makes effective a change to Gross Load of a

Participating TO directly connected to the Non-Load-Serving Participating TO. Using the Low Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for the Non-Load-Serving Participating TO, the CAISO will recalculate the Low Voltage Access Charge applicable during such period. Revisions to the low voltage TRBA adjustment shall be made effective annually on January 1 based on the principal balance in the low voltage TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

For service provided by a Non-Load-Serving Participating TO following the TAC Transition Date, any refund associated with a Non-Load-Serving Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced in the CAISO Market Invoice.

If the Non-Load-Serving Participating TO withdraws one or more of its transmission facilities from the CAISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the CAISO will no longer collect the TRR for that transmission facility through the CAISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the CAISO. The withdrawing Non-Load-Serving Participating TO shall be obligated to provide the CAISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at FERC to revise its TRR. The CAISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from CAISO Operational Control.

13.3 Approval of Updated Low Voltage Transmission Revenue Requirement. A Non-Load-Serving Participating TO will make the appropriate filings at FERC to establish its Transmission Revenue Requirement for its Low Voltage Access Charge, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the LVTRR and other information required by the FERC to support the Low Voltage Access Charge. The Non-Load-Serving Participating TO will provide a copy of its filing to the CAISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

Federal power marketing agencies whose transmission facilities are under CAISO Operational Control shall develop their Low Voltage Transmission Revenue Requirements pursuant to applicable federal laws and regulations, including filing with FERC. All such filings with FERC will include a separate appendix that states the LVTRR and other information required by the FERC to support the Access Charges. The procedures for public participation in a federal power marketing agency's ratemaking process shall be posted on the federal power marketing agency's website. The federal power marketing agency shall also post on the website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's Low Voltage Transmission Revenue Requirement. The Non-Load-Serving Participating TO will provide a copy of its filing to the CAISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

13.4 Disbursement of Low Voltage Access Charge Revenues. Unless otherwise agreed by the affected Participating TOs, Low Voltage Access Charge revenues of a Non-Load-Serving Participating TO shall be calculated for disbursement to that Non-Load-Serving Participating TO on a monthly basis as the sum of Low Voltage Access Charges billed by the CAISO to the UDCs or MSS Operators of Participating TOs pursuant to Section 26.1 of the CAISO Tariff.

13.5 Payment of Low Voltage Access Charge. Notwithstanding the separate accounting for the Low Voltage Access Charge specified in Section 26.1 of the CAISO Tariff and this Section 13 of this

Schedule 3, if the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount, and any Low Voltage Access Charge amount pursuant to this Section 13 of this Schedule 3, billed by the CAISO will be the charges payable by the UDC or MSS Operator in accordance with Sections 26.1.2 and 26.1 of the CAISO Tariff less the disbursement determined in accordance with Section 10.1(d) of this Schedule 3. If this difference is negative, that amount will be paid by the CAISO to the Participating TO.

14. Wheeling Access Charges.

14.1 CAISO Charges on Scheduling Coordinators for Wheeling. The CAISO will charge Scheduling Coordinators for a Wheeling Out or a Wheeling Through transaction the product of the Wheeling Access Charge and the total of the hourly Schedules or awards of Wheeling in MWh for each Trading Interval at each Scheduling Point associated with that transaction pursuant to Section 26.1.4 of the CAISO Tariff.

14.2 Wheeling Access Charge. The Wheeling Access Charge for each Participating TO shall be as specified in Section 26.1.4 of the CAISO Tariff.

14.3 CAISO Payments to Transmission Owners for Wheeling. The CAISO will pay all Wheeling revenues to Participating TOs on the basis of the ratio of each Participating TO's Transmission Revenue Requirement (less the TRR associated with Existing Rights) to the sum of all Participating TOs' TRRs (less the TRRs associated with Existing Rights) as specified in Section 26.1.4.3 of the CAISO Tariff and in the applicable Business Practice Manual. The Low Voltage Wheeling Access Charge shall be disbursed to the appropriate Participating TO in accordance with the applicable Business Practice Manual.

14.4 Weighted Average Rate for Wheeling Service. The weighted average rate payable for Wheeling over joint facilities at each Scheduling Point shall be calculated as the sum of the applicable Wheeling Access Charge rates for each applicable TAC Area or Participating TO as these rates are weighted by the ratio of the Available Transfer Capability for each Participating TO at the particular Scheduling Point to the total Available Transfer Capability for the Scheduling Point. The calculation of this rate is set forth in more detail in the applicable Business Practice Manual.

Schedule 4

Eligible Intermittent Resources Forecast Fee

A charge up to $.10 per MWh shall be assessed on the metered Energy from Eligible Intermittent Resources as a Forecast Fee, provided that Eligible Intermittent Resources smaller than 10 MW that are not Participating Intermittent Resources and that sold power pursuant to a power purchase agreement entered into pursuant to PURPA prior to entering into a PGA or QF PGA shall be exempt from the Forecast Fee.

The rate of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the CAISO as a direct result of participation by Eligible Intermittent Resources in CAISO Markets, divided by the projected annual Energy production by all Eligible Intermittent Resources.

The initial Forecast Fee, and all subsequent changes as may be necessary from time to time to recover costs incurred by the CAISO for the forecasting conducted on the behalf of Eligible Intermittent Resources pursuant to the foregoing rate formula, shall be set forth in a Business Practice Manual.

Participating Intermittent Resources Process Fee

A process fee charge shall be assessed, for each calendar quarter, to each Exporting Participating Intermittent Resource that exported Energy in the quarter. On an annualized basis, the aggregate quarterly charges shall total to $10,000. The charge is not volumetric, and shall be calculated as follows:

($10,000/4)/N = $quarterly charge
N = number of Participating Intermittent Resources exporting Energy in the quarter

Participating Intermittent Resources Export Fee

A Participating Intermittent Resources Export Fee shall be assessed to Exporting Participating Intermittent Resources each calendar month. The Participating Intermittent Resources Export Fee shall be calculated as the product of (1) the sum of all Settlement costs avoided by Participating Intermittent Resources for the preceding calendar month, or portion thereof, consisting of Charge Codes 6486 [Real Time Excess Cost For Instructed] and 1487 [Energy Exchange Program Neutrality], but excluding charges for Uninstructed Energy associated with Charge Code 6475, (2) by the ratio of the total MW/h generated by an Exporting Participating Intermittent Resource during the calendar month, or portion thereof (based on metered output), by the total MW/h generated by all Participating Intermittent Resources during the calendar month, or portion thereof (based on metered output), and (3) by the percentage of the Exporting Participating Intermittent Resource's capacity deemed exporting under Section 5.3 of the EIRP or PIR Export Percentage.

Participating Intermittent Resources Export Fee per Participating Intermittent Resource =

Program Costs x (MW/h individual Participating Intermittent Resource/MW/h all Participating Intermittent Resources) x PIR Export Percentage

Schedule 5
STATION POWER CHARGES

The CAISO shall assess a charge of $500 to the Scheduling Coordinator representing the owner of one or more Generating Units that submits an application to establish a Station Power Portfolio or to change the configuration of Station Power meters or the generating facilities included in a Station Power Portfolio. If the generating facilities in a single Station Power Portfolio are scheduled by more than one Scheduling Coordinator, then the Scheduling Coordinator representing the most installed capacity shall be assessed the application charge.

A charge of $200 will be assessed to the Scheduling Coordinator of Generating Units that have Station Power meters each time the CAISO is required to shift Meter Data to a unique Load identifier pursuant to the Station Power Protocol. For example, if a Scheduling Coordinator has two Station Power meters, and both Remote Self Supply and Third Party Supply is attributed to each Station Power meter in a single Netting Period, then the CAISO must shift Meter Data to a total of four unique Load identifiers and the charge would be $800 in that month (2 meters x 2 Load IDs x $200).

All revenue collected by the CAISO pursuant to this Schedule 5 shall be considered "Other Revenues" and applied as a credit to the Grid Management Charge revenue requirement in accordance with Schedule 1 of Appendix F.

Schedule 6
CPM SCHEDULES

Monthly CPM Capacity Payment

The monthly CPM Capacity Payment shall be calculated by multiplying the monthly shaping factor of 1/12 by the annual CPM Capacity price of $55/kW-year in accordance with Section 43.7.1, unless the Scheduling Coordinator for the CPM Capacity resource has agreed to another price that has been determined in accordance with Section 43.7.2.

Availability

The target availability for a resource designated under CPM is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The CAISO shall calculate availability on a monthly basis using actual availability data. The CPM Availability Factor for Forced Outages for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability	**Capacity Payment Factor**	**ICPM Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*****	.908-.755
79-41%	-1.9%*****	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The CPM Capacity Payment shall be adjusted upward from the 95% availability starting point by the positive percentages listed as the "Capacity Payment Factor" above, by multiplication by the amounts listed for each CPM Availability Factor above 95%, so that, for example, if a 97% availability is achieved for the month, then the CPM Capacity Payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent availability above 95%, and 2.5% for the second percent availability above 95%), i.e., multiplication of the otherwise applicable CPM Capacity Payment by the CPM Availability Factor of 1.040. Reductions in the CPM Capacity Payment shall be made correspondingly according to the "Capacity Payment Factor" above for monthly availability levels falling short of the 95% availability starting point, by multiplication by the amounts listed for each CPM Availability Factor below 95%.