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March 23, 2010

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

Re: California Independent System Operator Corporation
Docket No. ER10-188-000
Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602(b) of the Commission's Rules of Practice and Procedure, the California Independent System Operator Corporation ("ISO"), on behalf of itself and Calpine Corporation, Citigroup Energy, Inc., Dynegy Morro Bay, LLC, Dynegy Moss Landing LLC, Dynegy Oakland LLC, and Dynegy South Bay, LLC, Morgan Stanley Capital Group, Inc., Pacific Gas and Electric Company, Powerex Corp., San Diego Gas & Electric Company, and Southern California Edison Company, submits an Offer of Settlement in the above identified proceeding.

The background and terms of the Offer of Settlement are set forth in the attachments. Consistent with the Commission's regulations, the following documents are enclosed:

1. Offer of Settlement

   Attachment A. Tariff sheets implementing the Offer of Settlement.
   Attachment B. Black-lined versions of the tariff sheets.

2. Explanatory Statement

3. Draft Commission Order approving the settlement.

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

Respectfully submitted,

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1. OFFER OF SETTLEMENT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	Docket No. ER10-188-000

OFFER OF SETTLEMENT

The California Independent System Operator Corporation ("ISO"), on behalf of the "Settling Parties"[1] hereby offers the following terms and conditions of a settlement (the "Settlement") to each of the parties to the above-captioned proceeding. If approved by the Federal Energy Regulatory Commission, this Settlement will resolve all issues in this proceeding.

TERMS

The terms of the Settlement are as follows:

ARTICLE 1

DEFINITIONS

1.1 All defined terms shall have the meaning as set forth in the ISO's open access tariff as it exists on the Effective Date ("ISO Tariff") unless otherwise defined herein or in Attachment A to this Offer of Settlement ("Tariff Sheets").

[1] The Settling Parties, in addition to the ISO are, Calpine Corporation, Citigroup Energy, Inc., Dynegy Morro Bay, LLC, Dynegy Moss Landing LLC, Dynegy Oakland LLC, and Dynegy South Bay, LLC, Morgan Stanley Capital Group, Inc., Pacific Gas and Electric Company, Powerex Corp., San Diego Gas & Electric Company, and Southern California Edison Company. Any parties that join this Settlement subsequent to its being filed shall also constitute "Settling Parties."

ARTICLE 2

THE MARKET USAGE-FORWARD ENERGY CHARGE

2.1 Effective June 1, 2010, and continuing through December 31, 2011, Inter-Scheduling Coordinator Trades will be excluded from the calculation of the Market Usage-Forward Energy Charge of the ISO's Grid Management Charge. The Market Usage Forward Energy Charge will be calculated as the greater of a Scheduling Coordinator's Supply Schedules and Demand Schedules (including Self-Schedules) in the Day-Ahead Market.

2.2 To implement the Market Usage Forward Energy Charge calculation described in Section 2.1, the ISO Tariff is revised, effective June 1, 2010, as follows.

2.2.1 Appendix F, Schedule 1, Part A, Paragraph 7, in its entirety, is revised to read as follows:

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.

2.2.2 In Appendix F, Schedule 1, Part E, Paragraph:1, the sentence beginning with "MU-FE" and ending with "Day-Ahead Market" is revised to read as follows:

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.

2.3 Prior to filing its 2012 Grid Management Charge or proposing any further changes to the 2010 and 2011 Grid Management Charge other than the prospective Convergence Bidding Charge Type, the ISO will conduct a cost-of-service study and engage in a stakeholder process to determine the appropriate allocation of the costs of operating the ISO.

ARTICLE 3

EFFECTIVE DATE

3.1 This Settlement shall become effective upon issuance by the Commission of a Final Order approving this Settlement without modification or condition, or, if modified or conditioned, upon its acceptance as so modified by the Settling Parties as provided in Section 4.1.2 below.

3.2 For purposes of this Settlement, a Commission order shall be deemed to be a Final Order when the Commission issues an order approving this Settlement.

ARTICLE 4

MISCELLANEOUS

4.1 *Termination of Settlement.*

4.1.1 The ISO Tariff provisions implementing the terms of this Settlement shall automatically expire on December 31, 2011, unless extended by a filing under Section 205 of the Federal Power Act.

4.1.2 If the Commission, in approving this Settlement or by taking any other regulatory action, modifies the Settlement in a manner that materially changes the benefits and burdens negotiated herein, the Settling Parties shall meet and confer within 30 days as to whether all Settling Parties can agree to the modified Settlement. If all of the Settling Parties do not agree, in writing, to the modified Settlement, then the Settlement shall terminate.

4.2 *Precedential Value.* The Settling Parties agree that this Settlement shall have no precedential value, shall not be cited as precedent, and shall not be deemed to bind any Settling Party (except as otherwise expressly provided for herein) in any proceeding, including any FERC proceeding, except in any proceeding to enforce this Settlement. The Settling Parties further agree that this Settlement shall not be deemed to be a "settled practice" as that term was interpreted and applied in *Public Service Commission of the State of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

4.3 *Future Grid Management Charge Proceedings.* The Settlement shall have no effect on the rights of Settling Parties, during future proceedings concerning the ISO's 2012 Grid Management Charge proposal or any subsequent Grid Management

Charge proposal, to protest the ISO's proposed allocation of the costs of administering its forward markets and to advocate any alternative allocation. The Settlement shall have no effect on the rights of Settling Parties, during future proceedings concerning the ISO's 2011 Grid Management Charge proposal or any subsequent Grid Management Charge proposal, to protest any portion of the ISO's proposed Grid Management Charge other than the proposed allocation of the costs of administering its forward markets.

4.4 *Negotiated Settlement.* This Settlement is made upon the express understanding that it constitutes a negotiated settlement and, except as otherwise expressly provided for herein, no Settling Party shall be deemed to have approved, accepted, agreed to, or consented to any principle or policy relating to the rates, charges, classifications, terms, conditions, principles, issues or tariff sheets associated with this Settlement.

4.5 *Integration.* The Exhibits to this Settlement are hereby integrated into, and shall constitute part of, this Settlement.

4.6 *Entire Agreement.* The Settling Parties acknowledge and agree that this Settlement, including the Exhibits hereto, constitutes the full and complete agreement of the Settling Parties with respect to the subject matter addressed herein and supersedes all prior negotiations, understandings, and agreements, whether written or oral, between the Settling Parties with respect to the subject matter addressed herein.

4.7 *Standard of Review.* The Settling Parties intend for this Settlement to be subject to the just and reasonable standard of review.

4.8 *Settlement Privilege.* The Settling Parties agree that the discussions among them that have produced this Settlement have been conducted on the explicit understanding that they were undertaken subject to Rule 602(e) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602(e). The Settling Parties further agree that all offers of settlement, and any comments on such offers, and any discussions among the Settling Parties with respect to this Settlement are privileged, not admissible as evidence against any participant who objects to their admission, and not subject to discovery.

4.9 *Confidentiality.* The parties' agreement that all material subject to the protective order issued in this proceeding shall remain subject to that protective order, except to the extent that the ISO is permitted to release such material under the terms of the ISO Tariff.

4.10 *Support for Settlement/No Waiver of Rights.* The Settling Parties shall support this Settlement and shall cooperate in securing Commission acceptance and implementation of this Settlement. The Settling Parties hereby waive any and all rights to seek rehearing or judicial review of any Commission order(s) approving the Settlement without modification or condition; provided, however, that if the Commission approves the Settlement with modifications or conditions, any Party may seek rehearing or judicial review of the Commission order(s) approving the Settlement solely to challenge the Commission's imposition of such modifications or conditions in order to preserve the terms and conditions of the Settlement as filed. Notwithstanding any other provision of this Offer of Settlement, no party waives its rights under Section 205 or 206 of the Federal Power Act with respect to any provision of the ISO Tariff.

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

4.12 *Dispute Resolution.* Dispute resolution shall be in accordance with the CAISO Tariff.

Respectfully submitted,

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Dated: March 23, 2010

Attachment A – Clean Sheets

Fourth Replacement CAISO Tariff

March 23, 2010

5. The rate in $/MWh for the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Balancing Authority Area Load associated with Transmission Ownership Rights.

6. The rate in $ per Schedule or $ per Inter-SC Trade for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Day-Ahead and HASP Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service and Residual Unit Commitment Bids and all Inter-SC Trades, including Inter-SC Trades of IFM Load Uplift Obligations. This charge will be assessed separately with respect to Schedules and Inter-SC Trades.

7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with Uninstructed Imbalance Energy for Participating Intermittent Resources netted over the Trading Month and all other Uninstructed Imbalance Energy being netted within a Settlement Interval) in MWh. A Market Usage Charge rate will be calculated separately for two sets of CAISO Markets: (i) the Ancillary Services and RTM rate will be based on MWh of purchases and sales of Ancillary Services in the DAM, the HASP, and the RTM, MWh of Instructed Imbalance Energy, and MWh of Uninstructed Imbalance Energy netted over the Settlement Interval; and (ii) the rate for the Day-Ahead Market for Energy will be based on MWh of Day-Ahead Schedules. The rate for the Day-Ahead Market for Energy will be based on the sum, for all Scheduling Coordinators and all Settlement Periods, of the greater of the amount of MWh associated with each Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

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

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

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

<u>Part B – Quarterly Adjustment, If Required</u>

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 E – Cost Allocation

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

Debt service expenditures for the CAISO's existing bond offerings shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. Capital expenditures shall be allocated among the charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1, for the system for which the capital expenditure is projected to be made.

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

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

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

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

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

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

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

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

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

Attachment B – Blacklines

Fourth Replacement CAISO Tariff

March 23, 2010

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CAISO TARIFF APPENDIX F

Rate Schedules

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CAISO TARIFF APPENDIX F
Schedule 1

Grid Management Charge

<u>Part A – Monthly Calculation of Grid Management Charge (GMC)</u>

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

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

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

3. The rate in $/MWh for the Energy Transmission Services – Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Balancing Authority Area Load, excluding each Scheduling Coordinator's Metered Balancing Authority Area Load associated with Transmission Ownership Rights.

4. The rate in $/MWh for the Energy Transmission Services – Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net Uninstructed Imbalance Energy (netted within a Settlement Interval summed over the calendar month) in MWh; provided that the rate for each Scheduling Coordinator's Participating Intermittent Resources will be assessed against the Uninstructed Imbalance Energy of such Participating Intermittent Resources netted over the Trading Month.

5. The rate in $/MWh for the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service

category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Balancing Authority Area Load associated with Transmission Ownership Rights.

6. The rate in $ per Schedule or $ per Inter-SC Trade for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Day-Ahead and HASP Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service and Residual Unit Commitment Bids and all Inter-SC Trades, including Inter-SC Trades of IFM Load Uplift Obligations. This charge will be assessed separately with respect to Schedules and Inter-SC Trades.

7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with Uninstructed Imbalance Energy for Participating Intermittent Resources netted over the Trading Month and all other Uninstructed Imbalance Energy being netted within a Settlement Interval) in MWh. A Market Usage Charge rate will be calculated separately for two sets of CAISO Markets: (i) the Ancillary Services and RTM rate will be based on MWh of purchases and sales of Ancillary Services in the DAM, the HASP, and the RTM, MWh of Instructed Imbalance Energy, and MWh of Uninstructed Imbalance Energy netted over the Settlement Interval; and (ii) the rate for the Day-Ahead Market for Energy will be based on MWh of Day-Ahead Schedules~~net Energy purchases or sales in the DAM, offset by MWh of net Energy associated with Inter-SC Trades of Energy in the DAM~~. The rate for the Day-Ahead Market for Energy will be based on the sum, for all Scheduling Coordinators and all Settlement Periods, of the greater of the amount of MWh associated with each Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

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

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

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

* * *

Part 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~~net purchases or sales of Energy in the Day-Ahead Market~~. For each Scheduling Coordinator, the charge for the Day-Ahead Market for Energy will be based on the sum, for all Settlement Periods, of the greater of the amount of MWh associated with the Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.

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

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

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

* * *

2. EXPLANATORY STATEMENT IN SUPPORT OF OFFER OF SETTLEMENT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	Docket No. ER10-188-000

EXPLANATORY STATEMENT IN SUPPORT OF OFFER OF SETTLEMENT

Pursuant to 18 C.F.R. § 385.602(c)(1)(ii), the California Independent System Operator Corporation ("ISO"), on behalf of itself and Calpine Corporation, Citigroup Energy, Inc., Dynegy Morro Bay, LLC, Dynegy Moss Landing LLC, Dynegy Oakland LLC, and Dynegy South Bay, LLC, Morgan Stanley Capital Group, Inc., Pacific Gas and Electric Company, Powerex Corp., San Diego Gas & Electric Company, and Southern California Edison Company, submits this Explanatory Statement in support of the Offer of Settlement ("Settlement") submitted herewith.[1] This Settlement is intended to resolve all issues in the above-captioned proceeding.

I. BACKGROUND

On February 20, 2008, the ISO filed a tariff amendment revising its Grid Management Charge rate design to accommodate the ISO's market operations under its Market Redesign and Technology Update. The Commission accepted the ISO's

[1] This Explanatory Statement is not intended to alter any of the terms of the Offer of Settlement. In the event of any conflict between this Explanatory Statement and the terms of the Offer of Settlement, the Offer of Settlement shall govern. Unless otherwise stated, capitalized terms shall have the meanings provided, or incorporated by reference, in the Offer of Settlement.

proposed amendment, with the exception of two modifications that parties had protested.[2] The Commission directed the ISO to submit a compliance filing to include previously accepted language regarding load-following metered sub-systems that the ISO had proposed to delete from its tariff [3] and to propose tariff language addressing the treatment of Inter-Scheduling Coordinator Trades in calculating Market Usage-Forward Energy Charges.[4] The Market Usage-Forward Energy Charge is designed to recover the portion of the ISO's costs of administering its markets that is associated with forward energy purchases and sales.

On January 21, 2009, the ISO submitted its compliance filing. The ISO proposed to clarify that the Market Usage-Forward Energy Charge would apply to energy in the Day-Ahead Market as offset by physical (but not financial) Inter-Scheduling Coordinator Trades. In response to a protest filed by the Northern California Power Agency ("NCPA"), the ISO filed an answer in which it agreed that both types of trades should be included in the Market Usage-Forward Energy Charge allocation formula. The ISO offered to file tariff revisions with this clarification. Finally, the ISO stated that it would conduct a future stakeholder process to re-evaluate the Market Usage-Forward Energy Charge, including recovery of the administrative costs associated with Inter-Scheduling Coordinator Trades.[5]

In a March 2009 Order, the Commission accepted the ISO's Grid Management Charge compliance filing, subject to a further compliance filing by the ISO consistent

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

3 *Id.* at P 40.

4 *Id.* at P 46.

5 *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,021 at P4, *reh'g denied*, 129 FERC ¶ 61,293 (2009), citing ISO Answer, Docket No. ER08-585-001, filed February 26, 2009 at 3.

with the positions in the ISO's answer.[6] The Commission accepted the ISO's subsequent compliance filing on July 14, 2009.[7]

Consistent with its commitment, the ISO initiated a stakeholder process regarding the Market Usage Forward-Energy Charge on August 3, 2009, and held a stakeholder meeting on August 18, 2009. The ISO posted a straw proposal on August 28, 2009, and held a second stakeholder meeting on September 15, 2009. After a subsequent stakeholder conference call on September 30, 2009, the ISO posted its final proposal on October 2, 2009. The ISO conducted a final stakeholder conference call on October 21, 2009.

On October 30, 2009, the ISO filed proposed tariff revisions to extend the existing Grid Management Charge until December 31, 2010, with one exception: the CAISO proposed to revise the Market Usage-Forward Energy Charge (1) to exclude Inter-Scheduling Coordinator Trades from the calculation; (2) to base the charge on Day-Ahead energy schedules rather than purchases and sales; and (3) to calculate the charge based on the greater of a Scheduling Coordinator's total supply schedules or total demand schedules, rather than the difference between purchases and sales (the "modified gross" approach).

In support of its filing, the ISO noted that, although allocating the Market Usage-Forward Energy Charge to "gross" energy schedules, rather than "net" energy schedules, is most consistent with cost causation, replacing the current netting approach with a gross approach could have excessive rate impacts on some

6 *Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,289, at P 7 (2009).

7 *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,021.

Scheduling Coordinators. To mitigate these impacts, the ISO proposed the modified gross approach as an interim measure until the ISO's completion of a new cost-of-service study for the Grid Management Charge.

No parties protested the ISO's proposed amendment. Some, however, stated concerns about the proposed allocation of the Market Usage-Forward Energy Charge and expressed a preference for a different allocation, and others challenged the ISO's statements regarding cost causation. On December 30, 2009, the Commission accepted the ISO's amendment with one exception. The Commission found that the ISO had failed to justify the modified gross approach as just and reasonable. The Commission suspended the Market Usage-Forward Energy Charge for five months and set it for hearing.[8]

On January 20, 2010, Administrative Law Judge Judith A. Dowd convened a settlement conference. During the conference, the ISO presented additional information on the cost impact of the various potential allocations of the Market Usage-Forward Energy Charge and answered questions. Various parties expressed their positions on the ISO's proposal. Judge Dowd adjourned the settlement conference until March 3, 2010, so that the parties could exchange information and continue informal discussions.

On February 23, 2010, the ISO circulated a settlement proposal, which it revised on February 25, 2010. On March 3, 2010, the parties met telephonically for further discussions. Based on those discussions, the ISO made additional changes to the proposal. The ISO circulated a revised proposal on March 5, 2010. Subsequently, the other settling parties joined the ISO in making this settlement offer.

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8 *Cal. Indep. Sys. Operator Corp.*, 129 FERC ¶ 61,292, at P 22 (2009).

II. SUMMARY OF SETTLEMENT TERMS

A. Market Usage-Forward Energy Charge

The Settlement proposes the adoption of the modified gross allocation of the Market Usage-Forward Energy Charge as an interim resolution of the issues, pending the ISO's completion of a new cost-of-service analysis in preparation for its 2012 Grid Management Charge filing. Effective June 1, 2010, and continuing through December 31, 2011, Inter-Scheduling Coordinator Trades will be excluded from the calculation of the Market Usage-Forward Energy Charge of the ISO's Grid Management Charge. The Market Usage Forward Energy Charge will be calculated as the greater of a Scheduling Coordinator's Supply Schedules and Demand Schedules (including Self-Schedules) in the Day-Ahead Market.

Prior to filing its 2012 Grid Management Charge or proposing any further changes to the 2010 and 2011 Grid Management Charge other than the prospective Convergence Bidding Charge Type, the ISO will conduct a cost-of-service study and engage in a stakeholder process to determine the appropriate allocation of the costs of operating the ISO.

B. Termination Provisions

The Tariff provisions implementing the terms of the Settlement expire on December 31, 2011, which the Settling Parties anticipate will coincide with the expiration of the ISO's 2011 Grid Management Charge. Notwithstanding the foregoing, no party waives its Section 205 or 206 rights with respect to any provision of the ISO Tariff.

If the Commission, in approving the Settlement, or any other regulatory action, modifies the Settlement in a manner that materially changes the benefits and burdens negotiated herein, the Settling Parties shall meet and confer within 30 days as to whether all Settling Parties can agree to the modified Settlement. If all of the Settling Parties do not agree, in writing, to the modified Settlement, then the Settlement shall terminate.

III. ADDITIONAL INFORMATION

A. What are the issues underlying the settlement and what are the major implications?

The factual and procedural background of this proceeding, the issues underlying this proceeding, and the major implications of this proceeding have been summarized in Sections I and II above. The Settling Parties expressly agree that this is a negotiated settlement, that its terms set no precedent regarding future rates, and that during proceedings on the ISO's proposal for its 2012 Grid Management Charge, parties retain the right to protest the ISO's proposed allocation of the costs of administering its forward market and to advocate a different allocation. The Settlement resolves all issues between the Settling Parties.

B. Do any of the issues raise policy implications?

The Settlement furthers the broad public interest favoring settlements.[9] Beyond that, the Settlement does not raise policy implications.

C. Will other pending cases be affected?

The Parties do not believe that the Settlement affects any other pending cases.

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9 *See Southern Union Gas Co. v. FERC*, 840 F.2d 964, 971 (D.C. Cir. 1988).

D. Does the settlement involve issues of first impression, or are there any previous reversals on the issues involved?

The Settlement involves no issues of first impression, and there are no previous reversals on the issues involved in this proceeding.

E. Is the proceeding subject to the just and reasonable standard or is there *Mobile-Sierra* language making it the standard, *i.e.*, what are the applicable standards of review?

The Settling Parties intend the just and reasonable standard of review to apply to modifications to this Settlement.

IV. DUE DATES FOR COMMENTS

In accordance with Rule 602, initial comments on the Settlement are due April 12, 2010, and reply comments are due April 22, 2010.

V. CONCLUSION

The Settlement would fully resolve all of the issues raised in Docket No. ER10-188 on an interim basis. It will facilitate the ability of the Settling Parties to reevaluate those issues based on the development of new information and through new stakeholder proceedings. Commission approval of the Settlement will save the Settling Parties and the Commission the expense and risks associated with continued litigation.

For these reasons, the Settling Parties therefore respectfully request that the Commission approve the Settlement without modification.

Respectfully submitted,

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Dated: March 23, 2010

3. DRAFT COMMISSION ORDER APPROVING THE SETTLEMENT

In Reply Refer To:
California Independent System Operator Corporation
Docket No. ER10-188-000

Attn: Michael E. Ward
Counsel for California Independent
System Operator Corporation
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004-1404

Dear Mr. Ward:

On March 23, 2010, you filed an Offer of Settlement agreement in Commission Docket No. ER10-188-000 on behalf of the California Independent System Operator Corporation and Calpine Corporation, Citigroup Energy, Inc., Dynegy Morro Bay, LLC, Dynegy Moss Landing LLC, Dynegy Oakland LLC, and Dynegy South Bay, LLC, Morgan Stanley Capital Group, Inc., Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company. Comments in this proceeding were filed by ___________________ on ___________, 2010. Reply comments were filed by ___________________ on ___________, 2010.

The subject settlement is in the public interest and is hereby accepted. The Commission's acceptance of this settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding. The Commission retains the right to investigate the rates, terms and conditions under the just and reasonable and not unduly discriminatory or preferential standard of Section 206 of the Federal Power Act, 16 U.S.C. § 824e.

By direction of the Commission.

Secretary

Enclosure

cc: To All Parties

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service list for the above-referenced proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C. this 23rd day of March, 2010.

Michael E. Ward
Alston & Bird LLP