California ISO

California Independent System Operator Corporation

March 16, 2017

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

Re: California Independent System Operator Corporation
Filing of Rate Schedule No. 87
Docket No. ER17-_______-000

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits for filing and acceptance the Planning Coordinator Agreement dated November 29, 2016, between the CAISO and Southern California Edison Company (SCE).[1] The Planning Coordinator Agreement sets forth the terms under which the CAISO will serve as the Planning Coordinator[2] for the SCE bulk electric system facilities located within CAISO's balancing authority area that are not under CAISO operational control and that are listed in Attachment 1 to the Agreement (collectively, "SCE-Operated BES Facilities"). Under the Planning Coordinator Agreement, SCE will pay the CAISO an annual service fee for its services as Planning Coordinator during the initial three-year term of the agreement.

The CAISO respectfully requests that the Commission accept the Planning Coordinator Agreement. The agreement promotes reliability within the CAISO's balancing authority area, and compliance with NERC standards, by allowing the CAISO to serve as SCE's Planning Coordinator. The CAISO requests an effective date of May 16, 2017.

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1 The CAISO submits the Planning Coordinator Agreement pursuant to Rule 205 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.205 and Section 205 of the Federal Power Act, 16 U.S.C. § 824d.

2 The term "Planning Coordinator" is defined in the North American Electric Reliability Corporation ("NERC") Reliability Functional Model. The NERC Reliability Functional Model (Version 5) defines Planning Coordinator as "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas." *NERC Reliability Functional Model, Function Definitions and Functional Entities*, Version 5, page 22 (November 30, 2009).

I. Background

The North American Electric Reliability Corporation (NERC) Reliability Standards establish the Planning Authority, which is synonymous with the term "Planning Coordinator", as one of the functional entities within the NERC Functional Model. The CAISO is registered as a Planning Authority.[3] As required by NERC regulations, the Planning Authority coordinates and integrates transmission facility and service plans, resource plans, and protection system plans among the Transmission Planners, Resource Planners, and Distribution Providers within its area of purview.[4] These activities include the review and integration of reinforcement and corrective action plans developed by the functional entities (i.e., Planning Authority, Transmission Planner, and Resource Planner) whose area of responsibility is within the Planning Authority's area with respect to established reliability needs, as well as providing procedures, protocols, modeling and methodology software, etc. for consistent use within its area.

The NERC Reliability Functional Model further describes that the Planning Coordinator:

(1) coordinates and collects data for system modeling from Transmission Planners, Resource Planners, and other Planning Coordinators;

(2) coordinates transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinators, Transmission Owners, Transmission Operators, Transmission Service Providers, and neighboring Planning Coordinators;

(3) coordinates plans with the Reliability Coordinator and other Planning Coordinators on reliability issues;

(4) receives plans from Transmission Planners and Resource Planners;

(5) collects information including: (a) transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators; (b) demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners; (c) generator unit performance characteristics and capabilities from Generator Owners; and (d) long-term capacity purchases and sales from Transmission Service Providers;

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[3] The CAISO is also registered as a Balancing Authority, Transmission Operator, and Transmission Service Provider.

[4] NERC Reliability Functional Model, Function Definitions and Functional Entities, Version 5, pages 22-23.

(6) collects and reviews reports on transmission and resource plan implementation from Resource Planners and Transmission Planners;

(7) submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate;

(8) provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system; and

(9) facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.[5]

Through its Transmission Control Agreement, the CAISO currently acts as the Planning Coordinator for its participating transmission owners, who have transferred their transmission lines and associated facilities to the CAISO's operational control. Consistent with the CAISO's registration as a Planning Coordinator, its participating transmission owners are registered as Transmission Planners.

There are other transmission owners, known as "adjacent systems," who have facilities or systems that are connected to the transmission network under CAISO operational control, but are not within the CAISO's planning coordinator boundary. Some of these transmission owners do not have a Planning Coordinator for these particular systems and facilities. Because these adjacent systems are not within the CAISO's planning coordinator area boundary, the NERC regulations do not require the CAISO to be their Planning Coordinator. NERC regulations do, however, require these adjacent systems to be responsible for the planning of their own systems and facilities and, thus, to be represented by a registered Planning Coordinator.

Recently, the CAISO identified several adjacent systems who are not represented by a Planning Coordinator with respect to some or all of their systems or facilities under CAISO operational control. In an effort to enhance system reliability under the NERC Functional Model, the CAISO offered to provide Planning Coordinator services on behalf of these adjacent systems. SCE expressed an interest in the CAISO's offer.[6]

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[5] *Id.*

[6] SCE is registered with NERC as a Transmission Owner. The CAISO is also discussing this offer with other parties.

After further discussions with SCE, the parties negotiated and executed a Planning Coordinator Agreement, whereby the CAISO has agreed to serve as the Planning Coordinator for SCE with respect to the SCE-Operated BES Facilities in exchange for a modest service fee, discussed in detail below. This agreement allows adjacent systems, like SCE, to have a Planning Coordinator and, thus, furthers the NERC reliability objective that all transmission owners have a Planning Coordinator for their Bulk Electric System facilities.

II. The Planning Coordinator Agreement

The Planning Coordinator Agreement details the contractual terms, including the scope of work and the fee, under which the CAISO will provide Planning Coordinator services to SCE. The fundamental purposes served by the Planning Coordinator Agreement are described below.

A. The Planning Coordinator Agreement Establishes the Parties' Respective Responsibilities

The Planning Coordinator Agreement establishes the respective obligations of the CAISO and SCE, which are set forth in Article II.

Specifically, the CAISO must maintain its registration as a Planning Coordinator with NERC and serve as the Planning Coordinator for the SCE-Operated BES Facilities. In conjunction with these services, the CAISO will be responsible for compliance, as determined by the Commission, NERC, and the Western Electricity Coordinating Council, with all reliability standards applicable to a Planning Coordinator for the SCE-Operated BES Facilities. Because the CAISO is already a Planning Coordinator for its participating transmission owners, it will be able to leverage its existing processes in serving as the Planning Coordinator for SCE.

SCE is responsible for maintaining its registration with NERC as a Transmission Planner. SCE is also responsible for ensuring that it is in compliance, as determined by the Commission, NERC and the Western Electricity Coordinating Council, with all reliability standards applicable to a Transmission Planner for the SCE-Operated BES Facilities. Consistent with its responsibility to meet reliability standards applicable to a Transmission Planner and a Transmission Owner, SCE is solely responsible for implementing necessary corrective actions, modifications or changes to the SCE-Operated BES facilities.

B. The Planning Coordinator Agreement Describes the Parties' Duties of Cooperation and Coordination

To facilitate the fulfillment of the parties' roles and responsibilities, Article III of the Planning Coordinator Agreement sets forth the parties' duties of cooperation and coordination with each other.

Specifically, Attachment 2 to the Planning Coordinator Agreement illustrates the various areas in which the parties will coordinate their efforts, including the sharing and assessment of data related to interconnections, transmission planning, transfer capability and stability limits, modeling, uninstructed flow limits, and transmission relay loadability. In addition, the parties will cooperate with each other regarding all compliance related activities with respect to the Planning Coordinator and Transmission Planner functions. This includes complying with a reasonable request for data or assistance from the other party to demonstrate compliance with an applicable Reliability Standard and to support the party's self-certifications, potential violation reviews or audits.

C. The CAISO Will Charge SCE an Annual Service Fee in Exchange for Its Planning Coordinator Services

The Planning Coordinator Agreement specifies that SCE will pay an annual service fee during the initial three-year term of the agreement.[7] The fee reflects SCE's pro rata share of the CAISO's costs for transmission planning. The CAISO calculated the costs of transmission planning in a 2013 cost of service study that formed the basis of the CAISO's 2015 Grid Management Charge Update. The CAISO allocated costs to SCE based on its number of circuits of transmission facilities as a portion of the total number of circuits of transmission facilities for which the CAISO conducts planning. The discussion paper of the 2015 Grid Management Charge Update and spreadsheets documenting the derivation and allocation of the transmission planning costs are included with the Declaration of April Gordon in Attachment B.[8]

D. Other Provisions

The Planning Coordinator Agreement includes a variety of standard provisions that round out the parties' commitments. These include confidentiality (Section 4.2), termination (Section 4.4), dispute resolution (Section 4.5),

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[7] Planning Coordinator Agreement, Section 4.1 and Exhibit A. The CAISO anticipates that the service fee for the first year of the term of the Agreement will be approximately $15,524.

[8] The cost allocation methodology used to determine the annual service fee for SCE is the same methodology used for calculating the annual service fee for the City and County of San Francisco and the Metropolitan Water District of Southern California in connection with their Planning Coordinator Agreements with the ISO and which were approved by the Commission in 2015 and 2016, respectively.

representations and warranties (Section 4.6), limitations of liability (Section 4.7.1), governing law and venue (Section 4.13) and certain miscellaneous provisions.

III. Next Steps

Following Commission acceptance of this filing, the CAISO will complete the transmission plan studies and its collection and assessment of the data necessary to meet its Planning Coordinator obligations.

IV. Effective Date

The CAISO requests that the Planning Coordinator Agreement be made effective May 16, 2017, which is 61 days from the date of this filing.

V. Request for Confidential Treatment

Attachment 1 to the Planning Coordinator Agreement is a diagram of the SCE-Operated BES Facilities and, thus, includes Critical Energy Infrastructure Information (CEII) (as defined in 18 C.F.R. § 388.113) that is being submitted pursuant to 18 C.F.R. § 388.112. Accordingly, the information is exempt from mandatory public disclosure requirements under the Freedom of Information Act (FOIA), 5 U.S.C. § 552, and should be withheld from public disclosure. Notwithstanding this fact, the CAISO requests that the Commission provide the CAISO with notice of any FOIA requests and the opportunity to participate in any proceeding initiated to determine whether the Commission should direct disclosure of the aforementioned information.

VI. Request for Waivers

The CAISO believes this filing constitutes a new service (Planning Coordinator services) to a customer (SCE), and is an initial rate schedule that is subject to, and substantially complies with, section 35.12 of the Commission's regulations, 18 C.F.R. § 35.12 (2016), applicable to filings of this type. The CAISO respectfully requests waiver of any such requirement to the extent this filing does not satisfy that requirement.

In the event the Commission concludes that this filing is a change in a rate tariff or service agreement, the CAISO submits that the filing also substantially complies with the requirements of section 35.13 of the Commission's rules, 18 C.F.R. § 35.13 (2016), applicable to filings of this type. The CAISO respectfully requests waiver of any such requirement to the extent this filing does not satisfy that requirement.

In either event, there is good cause to waive filing requirements that are not material to the Commission's consideration of the Planning Coordinator Agreement.

VII. Service

The CAISO has served copies of this filing upon all scheduling coordinators, the California Public Utilities Commission, and the California Energy Commission. In addition, the CAISO has posted the filing on the CAISO website.

Enclosed for filing is each of the following:

(1) This letter of transmittal;

(2) Planning Coordinator Agreement (Attachment A) redacted to omit Attachment 1, which contains CEII information;

(3) Attachment (Attachment B); and

(4) Declaration of April Gordon, Director of Financial Planning and Procurement (Attachment C).

VIII. Correspondence

Pursuant to Rule 203(b) of the Commission's Rules of Practice and Procedure (18 C.F.R § 385.203(b)(3)), the CAISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

John E. Spomer
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 608-7257
Fax: (916) 608-7222
E-mail: jspomer@caiso.com

IX. Conclusion

The CAISO respectfully requests that the Commission accept this filing and permit the Planning Coordinator Agreement, CAISO Rate Schedule No. 87, to be effective May 16, 2017. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

By: *<u>/s/ John E. Spomer</u>*
Roger E. Collanton
General Counsel
Burton Gross
Assistant General Counsel
John E. Spomer
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 608-7257
Fax: (916) 608-7222
jspomer@caiso.com

Attorneys for the California Independent
System Operator Corporation

Redacted Pursuant to 18 C.F.R. § 388.112

This Document Contains Critical Energy Infrastructure Information

Attachment A – Public Clean Tariff Sheets

Planning Coordinator Agreement between the

California Independent System Operator Corporation and

Southern California Edison

Public Version

CEII Material Redacted

PLANNING COORDINATOR AGREEMENT

THIS AGREEMENT is dated this 29th day of November 2016, and is entered into, by and between:

(1) Southern California Edison Company, a California investor-owned utility, having its registered and principal place of business located at 2244 Walnut Grove Avenue, Rosemead, California, 91770 ("SCE");

and

(2) California Independent System Operator Corporation, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the CAISO Governing Board may from time to time designate, initially 250 Outcropping Way, Folsom, California 95630 ("CAISO").

SCE and the CAISO are hereinafter referred to as the "Parties."

RECITALS

A. WHEREAS, Section 215 of the Federal Power Act, 16 USC 824o, requires all users, owners and operators of the bulk-power system to comply with applicable reliability standards approved by the Federal Energy Regulatory Commission ("FERC") ("Reliability Standards"); and

B. WHEREAS, North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC") have developed Reliability Standards, certain of which apply to CAISO and SCE, and NERC has delegated to WECC enforcement of the Reliability Standards in the Western United States including California; and

C. WHEREAS, SCE is a Participating Transmission Owner ("PTO") with Bulk Electric System ("BES") facilities located within CAISO's Balancing Authority Area ("BAA") that are not under CAISO operational control (collectively, "SCE-Operated BES Facilities); and

D. WHEREAS, the SCE-Operated BES Facilities are set forth in the diagram attached as Attachment 1 (Attachment 1 contains Confidential Information, including Critical Energy Infrastructure Information, and is subject to Section 4.2 of this Agreement); and

E. WHEREAS, SCE is registered with NERC as a Generation Owner, Distribution Provider, Transmission Owner, Transmission Operator, and

Transmission Planner under the name of Southern California Edison Company ("SCEC"); and

F. WHEREAS, CAISO is registered with NERC as a Planning Authority (which is synonymous with "Planning Coordinator"); and

G. WHEREAS, there is a need for SCE to identify a Planning Coordinator for its SCE-Operated BES Facilities, currently and into the foreseeable future; and

H. WHEREAS, CAISO has determined it is qualified to be the Planning Coordinator for the SCE-Operated BES Facilities; and

I. WHEREAS, pursuant to this Agreement, CAISO agrees to be the Planning Coordinator for the SCE-Operated BES Facilities; and

J. WHEREAS, the Parties are entering into this Agreement in order to establish the terms and conditions on which CAISO and SCE will discharge their respective duties and responsibilities.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, the PARTIES AGREE as follows:

AGREEMENT

ARTICLE I

DEFINITIONS AND INTERPRETATION

1.1 Definitions. Capitalized words in this Agreement that are not defined herein shall have the meanings set forth in NERC's "Glossary of Terms Used in NERC Reliability Standards" ("NERC Glossary of Terms").

1.2 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

(a) if there is any inconsistency between this Agreement and the NERC Glossary of Terms, the NERC Glossary of Terms will prevail to the extent of the inconsistency;

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

(c) the masculine shall include the feminine and neutral and vice versa;

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

(e) references to an Article, Section or Attachment shall mean an Article, Section or Attachment of this Agreement, as the case may be, unless the context otherwise requires;

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

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

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

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

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

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

ARTICLE II

GENERAL RESPONSIBILITIES OF THE PARTIES

2.1 Description of CAISO Responsibilities. While the Agreement is in effect, CAISO shall have the following responsibilities, including:

(a) CAISO is registered with NERC as a Planning Authority (which is synonymous with Planning Coordinator); and

(b) CAISO will serve as the Planning Coordinator (as that term is defined in the NERC Reliability Functional Model) for the SCE-Operated BES Facilities;

(c) While the Agreement is in effect, CAISO will be responsible for compliance, as determined by FERC, NERC and WECC, with all

Reliability Standards applicable to a Planning Coordinator for the SCE-Operated BES Facilities.

2.2 **Description of SCE Responsibilities.** While the Agreement is in effect, SCE shall have the following responsibilities, including:

(a) SCE is registered with NERC as a Transmission Planner; and

(b) SCE will be responsible for compliance, as determined by FERC, NERC and WECC, with all Reliability Standards applicable to a Transmission Planner for the SCE-Operated BES Facilities.

ARTICLE III

PROCEDURES AND COMPLIANCE

3.1 **Coordination.** The Parties agree that, for illustrative purposes only, Attachment 2 to this Agreement describes how CAISO and SCE anticipate coordinating with each other while carrying out their respective responsibilities as a Planning Coordinator and Transmission Planner with respect to the SCE-Operated BES Facilities. SCE and CAISO may revise Attachment 2 by mutual written agreement. Notwithstanding the illustration set forth in Attachment 2, the Parties agree that the procedures utilized to comply with applicable standards for the SCE-Operated BES Facilities will mirror those utilized to comply with applicable standards for the CAISO-Operated BES Facilities. No separate procedure will be required. Furthermore, the Parties agree that they must each meet their respective responsibilities as Planning Coordinator and Transmission Planner.

3.2 **CAISO's Use Of Existing Practices, Procedures and Processes.** Except as otherwise agreed by the Parties, to the extent applicable, CAISO will utilize its existing practices, procedures, and processes in performing its responsibilities as the Planning Coordinator for the SCE-Operated BES Facilities. For the avoidance of doubt, the Parties clarify that requests for new or modified interconnections to the SCE-Operated BES Facilities may be processed pursuant to the interconnection procedures adopted by SCE, and are not required to be undertaken pursuant to CAISO's existing practices, procedures and process for interconnections to PTO facilities.

3.3 **Interconnections to PTO Facilities.** This Agreement does not change the respective rights and responsibilities of CAISO and SCE with respect to interconnections to other facilities.

3.4 SCE's Responsibility for the SCE-Operated BES Facilities. SCE will coordinate and cooperate with CAISO in accordance with applicable Reliability Standards and will seek in good faith to reach agreement where possible on study assumptions, impacts and acceptable solutions. Nonetheless, consistent with its responsibility to meet Reliability Standards applicable to a Transmission Planner and a Transmission Owner, SCE has final authority over and is solely responsible for implementing necessary corrective actions, modifications or changes to the SCE-Operated BES Facilities.

3.5 Provision of Data. SCE will provide to CAISO in a timely manner all model data, including facility ratings, necessary for CAISO to perform the studies required for CAISO to fulfill its responsibilities as Planning Coordinator for the SCE-Operated BES Facilities. Whenever and to the extent practicable, SCE will provide the aforementioned data to the CAISO as part of the existing PTO data collection process, and no separate process or procedure will be required.

3.6 Compliance.

3.6.1 The Parties will cooperate with each other with respect to all compliance-related activities, including but not limited to audits, and with respect to the Transmission Planner and the Planning Coordinator functions.

3.6.2 Each Party shall comply with a reasonable request for data or assistance from the other Party to the extent reasonably necessary to demonstrate compliance with an applicable Reliability Standard, including providing reports or data reasonably necessary to support the other party's self-certifications, potential violation reviews, or audits.

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.1 Payment.

4.1.1 Annual Service Fee. SCE will compensate CAISO for its services as Planning Coordinator under this Agreement by paying CAISO an annual service fee ("Annual Fee"), which will be based on the cost methodology set forth in this Section 4.1.1.

CAISO shall invoice SCE for the first Annual Fee within thirty (30) days of the Effective Date, and shall invoice SCE within thirty (30) days of each anniversary to the Effective Date during the Current

Term consistent with Section 4.1.3. SCE will pay the invoice no later than thirty (30) days after receipt thereof.

The annual service fee will be based on the number of BES transmission circuits that comprise the SCE-Operated BES Facilities and included in the CAISO's Transmission Register multiplied by CAISO's long term transmission planning process ("TPP") cost per transmission circuit.

The TPP cost per transmission circuit will be based on the CAISO annual budget and Grid Management Charge Rates as amended from time to time and the total number of circuits owned by the PTOs included in CAISO's most current transmission plan. The calculation of the annual service fee for each year of the Current Term is set forth in Attachment 3. Subsequent annual service fees will be calculated in the same manner using data from the most recently published California ISO Grid Management Charge Update Cost of Service Study. This Section 4.1.1 shall not modify or abrogate SCE's obligation to compensate the CAISO, for performing Planning Coordinator function SCE-owned BES Facilities that are under CAISO operational control, as part of the Grid Management Charge.

4.1.2 Not Used.

4.1.3 Invoices. Invoices furnished CAISO under this Agreement will be in a form acceptable to SCE, based on existing invoicing practices, and will include a unique invoice number. Payment shall be made by SCE to CAISO at the address specified in Attachment 4 to this Agreement.

4.2 Confidentiality.

4.2.1 Both Parties understand and agree that, in the performance of the work or services under this Agreement or in contemplation thereof, a Party (a "Recipient") may have access to private or Confidential Information (as defined below) which may be owned or controlled by the other Party (a "Discloser") and that such information may contain proprietary or confidential details, the disclosure of which to third parties may be damaging to the Discloser. Both Parties agree that all Confidential Information disclosed by a Discloser to a Recipient shall be held in confidence by the Recipient and used only in performance of the Agreement, except to the extent such information is required to be disclosed by local, State or Federal laws and regulations or by court or public agency order. A Recipient shall exercise the same standard of care to protect a Discloser's confidential information as a reasonably prudent contractor would use to protect its own proprietary data. "Confidential Information" means (i) all written materials marked "Confidential," "Proprietary" or with words of similar import provided to either Party by the other Party, and (ii) all observations of equipment (including computer screens) and oral disclosures related to either Party's systems, operations and activities that are indicated as such at the time of observation or disclosure, respectively, provided that such indication is confirmed in writing within five (5) business days of the disclosure. Confidential Information includes portions of documents, records and other material forms or representations that either Party may create, including but not limited to, handwritten notes or summaries that contain or are derived from such Confidential Information.

4.2.2 In the event that disclosure of confidential or proprietary information is required by local, State or Federal laws and regulations or by court or public agency order, the Recipient shall give prior written notice to the Discloser as far in advance as reasonably possible. The Recipient shall cooperate with the Discloser in the event the Discloser seeks a protective order or other appropriate remedy to prevent such disclosure and, if such a protective order or other remedy cannot be obtained by such Discloser, the Recipient shall disclose only that portion of the confidential or proprietary information that is legally required to be disclosed.

4.2.3 Notwithstanding Sections 4.2.1 and 4.2.2 above, each Party to this Agreement shall not have breached any obligation under this Agreement if Confidential Information is disclosed to a third party when the Confidential Information: (a) was in the public domain at the time of such disclosure or is subsequently made available to the public consistent with the terms of this Agreement; or (b) had been received by either Party at the time of disclosure through other means without restriction on its use, or had been independently developed by either Party as shown through documentation; or (c) is subsequently disclosed to either Party by a third party without restriction on use and without breach of any agreement or legal duty; or (d) subject to the provisions of Section 4.2.2, is used or disclosed pursuant to statutory duty or an order, subpoena or other lawful process issued by a court or other governmental authority of competent jurisdiction.

4.2.4 The Parties acknowledge that the CAISO must comply with Section 20 of the CAISO Tariff.

4.2.5 CEII. The Parties further understand and agree that, in the performance of the work or services under this Agreement or in contemplation thereof, a Recipient (as defined in Section 4.2.1) may have access to information that comprises CEII (as defined below) which may be owned or controlled by the Discloser. Both Parties agree that all properly marked CEII disclosed by a Discloser to a Recipient shall be maintained by Recipient in a secure place, and shall not be made available to any third party, except to the extent such information is required to be disclosed by local, State or Federal laws and regulations or by court or public agency order, in which case Parties agree that the requirements of Section 4.2.2 shall apply to CEII. The term “CEII” means Critical Energy Infrastructure Information as defined by the FERC in 18 C.F.R. § 388.113(c)(1). CEII shall include: (A) materials provided by Discloser in accordance with this Agreement and designated by Discloser as CEII; (B) any information contained in or obtained from such designated materials; (C) notes of CEII; and (D) copies of CEII. Discloser shall physically mark the CEII on each page as “PROTECTED MATERIALS – Contains Critical Energy Infrastructure Information” or with words of similar import as long as the term “CEII” is included in that designation to indicate that they are CEII.

4.3 Effective Date. This Agreement shall be effective as of the later of the date it is executed by the Parties or the date accepted for filing and made effective by FERC (“Effective Date”) and shall remain in full force and effect for three (3) years from the Effective Date (“Current Term”) or as terminated pursuant to Section 4.4 of this Agreement. The Parties may mutually agree in writing to extend the term of the Agreement at any time.

4.4 Termination.

4.4.1 Termination by CAISO. CAISO may terminate this Agreement by giving sixty (60) days prior written notice of termination to SCE, in the event that SCE commits any material default under this Agreement which, if capable of being remedied, is not remedied within thirty (30) days after CAISO has given to SCE written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Section 4.9 of this Agreement. In addition, CAISO may terminate this Agreement by giving not less than a one year prior written notice of termination to SCE. With respect to any notice of termination given pursuant to this Section, if filing at FERC is required for this Agreement, CAISO must file a timely notice of termination with FERC. In the case of a SCE uncured material default, the filing of the notice of termination by CAISO with FERC will be considered timely if the filing of the notice of termination is made after the preconditions for termination have been met, and CAISO files the notice of termination within sixty (60) days after issuance of the notice of default. The notice of termination shall become effective on the later of (i) the date specified in the notice of termination, or (ii) in the event filing of the notice of termination is required, the date FERC accepts such notice.

4.4.2 Termination by SCE. SCE may terminate this Agreement by giving not less than sixty (60) days prior written notice of termination to CAISO. With respect to any notice of termination given pursuant to this Section, if filing at FERC is required for this Agreement, CAISO must file a timely notice of termination with FERC. The filing of the notice of termination by CAISO with FERC will be considered timely if the request to file a notice of termination is made, and CAISO files the notice of termination with FERC within thirty (30) days of receipt of SCE's notice of termination. The notice of termination shall become effective on the later of (i) the date specified in the notice of termination, or (ii) in the event filing of the notice of termination is required, the date FERC accepts such notice.

4.4.3 Termination by Mutual Agreement. The Parties may terminate this Agreement at any time upon mutual agreement in writing.

4.4.4 Effect of Expiration or Termination. Upon the expiration or termination of this Agreement for any reason, each Party will be released from all obligations to the other Party arising after the date of expiration or termination, except that expiration or termination of this Agreement will not (i) relieve either Party of those terms of this Agreement which by their nature are intended to survive, including without limitation Section 4.1.3 (Invoices), Section 4.2 (Confidentiality), Section 4.5 (Dispute Resolution), Section 4.6 (Representations and Warranties), Section 4.7 (Liability), Section 4.8 (Insurance), Section 4.11 (Notices), Section 4.13 (Governing Law and Forum), and Section 4.17 (Severability), (ii) relieve SCE of its payment obligations for services already rendered in accordance with the terms of this Agreement, or (iii) relieve either Party from any liability arising from any breach of this Agreement.

4.4.5 Transition Assistance. Except in the case of a termination for a default by SCE, if SCE so requests, CAISO will reasonably assist SCE to transition to another Planning Coordinator, including providing data and assistance, provided that SCE will reimburse CAISO for its reasonable costs of such assistance.

4.5 Dispute Resolution. The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. If such efforts do not result in settlement, Section 4.13 shall apply.

4.6 Representation and Warranties. Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.

4.7 Liability.

4.7.1 Limitation of Liability. Neither Party shall be liable to the other Party under any circumstances, whether any claim is based on contract or tort, for any special, consequential, indirect or incidental damages, including, but not limited to, lost profits, loss of earnings or revenue, loss of use, loss of contract, or loss of goodwill, arising out of or in connection with this Agreement or the services performed in connection with this Agreement.

4.7.2 Assessment of Penalties. If FERC, NERC, or WECC assesses one or more monetary penalties against CAISO as a Planning Coordinator for the violation of one or more Reliability Standards, and the conduct or omission(s) of SCE contributed, in whole or in part, to the violation(s) at issue, then the CAISO may recover from SCE that portion of the penalty that resulted from SCE's conduct or omissions(s), provided that each of the conditions set forth in Section 14.7.2.1 of the CAISO Tariff are met, except that references to the Market Participant that caused or contributed to the violation at issue should be taken to be references to SCE, and instead of the payment provisions described in Section 14.7.2.5 of the CAISO Tariff, the payment provisions in Section 4.1.3 of this Agreement shall apply.

4.8 Insurance. CAISO is responsible for maintaining in force, during the full term of the Agreement, reasonable levels of Commercial General Liability, Workers' Compensation, Commercial Auto Liability and Professional Liability insurance coverage.

4.9 Uncontrollable Forces Tariff Provisions. The Parties agree that Section 14.1 of the CAISO Tariff shall be incorporated by reference into this Agreement except that all references in Sections 14.1, 14.2 and 14.3 of the CAISO Tariff to Market Participants shall be read as a reference to SCE and references to the CAISO Tariff shall be read as references to this Agreement.

4.10 Assignments. Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the CAISO Tariff. In the case of SCE, a prior written consent must be executed and approved in the same manner as this Agreement. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.

4.11 Notices. The Parties agree that any notice, demand or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4.1 of the CAISO Tariff, provided that all references in Section 22.4.1 of the CAISO Tariff to Market Participants shall be read as a reference to SCE and references to the CAISO Tariff shall be read as references to this Agreement, and unless otherwise stated or agreed shall be made to the representative of the other Party indicated in Attachment 4. A Party must update the information in Attachment 4 of this Agreement as information changes. Such changes shall not constitute an amendment to this Agreement.

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

4.13 Governing Law and Forum. This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement, shall be brought in any of the following forums, as appropriate: any court of the State of California or any federal court of the United States of America located in Sacramento in the State of California, or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.

4.14 Compliance with Laws. The Parties shall keep themselves fully informed of all federal, state and local laws in any manner affecting the performance of this Agreement, and must at all times comply with such applicable laws as they may be amended from time to time.

4.15 Subcontracting. Neither Party may subcontract this Agreement, or any part of thereof, unless such subcontracting is first approved by the other

Party in writing. Neither Party shall, on the basis of this Agreement, contract on behalf of or in the name of the other Party. An agreement made in violation of this provision shall confer no rights on any Party and shall be null and void.

4.16 Merger. This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereof and supersedes all prior agreements, whether written or oral, with respect to such subject matter.

4.17 Severability. If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

4.18 Amendments. This Agreement and the Attachments hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective.

Nothing contained herein shall be construed as affecting in any way the right of CAISO to unilaterally make application to FERC for a change in the rates, terms and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder, and SCE shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 or any other applicable provision of the FPA and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the FPA and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

4.19 Counterparts. This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation:

By: DocuSigned by: Eric Schmitt 0971A84CB55B4B8...

Name: Eric Schmitt

Title: VP, Operations

Date: 11/21/2016

Southern California Edison Company:

By: DocuSigned by: Nestor Martinez C32F3E3929934D5...

Name: Nestor Martinez

Title: VP, Engineering and Technical Services

Date: 11/29/2016

Attachment 1

Diagrams

[Following two pages]

CRITICAL ENERGY INFRASTRUCTURE
INFORMATION
REDACTED PURSUANT TO
18 CFR § 388.112

Attachment 2

CAISO and SCE Coordination

The items enumerated below in this Attachment 2 indicate which Reliability Standards are currently applicable to the SCE-Operated BES Facilities, and provide, for illustrative purposes only, a description of how CAISO and SCE anticipate coordinating with each other while carrying out their respective responsibilities as a Planning Coordinator and Transmission Planner with respect to the SCE-Operated BES Facilities. Notwithstanding the specific language in this Attachment 2, Parties agree that the version of each applicable Reliability Standard enforceable at any given date shall be the basis for compliance on that date. Parties further agree that the procedures used to comply with applicable standards for the SCE-Operated BES Facilities will mirror those contemporaneously utilized to comply with applicable standards for the CAISO-Operated BES Facilities. No separate procedure will be required.

1. Facility Interconnection Studies

Applicable standards: FAC-002-2, and/or any successor standard(s) subject to enforcement.\The purpose of FAC-002-2 is to study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.

2. Transmission Planning

Applicable standards: TPL-001-4; WECC Regional Criteria TPL-001-WECC-CRT-3, TPL-007-1 (when applicable and enforceable), and/or any successor standard(s) subject to enforcement.

SCE participates in the CAISO Transmission Planning Process (TPP). SCE submits to the CAISO information about SCE system facilities that the CAISO requires to undertake its TPP. The CAISO complies with TPL-001-4 and the WECC Regional Criteria TPL-001-WECC-CRT-3 in its TPP studies, and undertakes its TPP in accordance with its Tariff and BPMs. TPL-007-1 pertains to transmission system planned performance for geomagnetic disturbance events. CAISO as the Planning Coordinator and SCE as the Transmission Planner and Transmission Owner will identify their roles and responsibilities in a matrix identifying which entity will maintain models (i.e., GIC models) and perform studies for GMD Vulnerability Assessments.

3. SOLs & IROLs, Transfer Capability, and Stability Limits

Applicable standards: FAC-010-2.1; FAC-013-2; FAC-014-2, and/or any successor standard(s) subject to enforcement.

CAISO documents and shares its SOL Methodology for use in developing SOLs and IROLs within its Planning Authority Area, and includes sharing its SOL Methodology with SCE. SCE will provide to CAISO any SOLs and IROLs that it may establish for the SCE system consistent with the CAISO SOL Methodology. CAISO will adopt SOLs and IROLs for its Planning Authority Area, incorporating as appropriate the information provided by SCE. SCE will provide CAISO SCE BES Facility ratings for CAISO to include in its transfer capability studies performed under FAC-013-2. CAISO will provide its Transfer Capability Methodology and assessment results to SCE. SCE will provide to CAISO SCE's list of multiple SCE/Adjacent System contingencies (if any) which result in stability limits on the SCE system for use by the CAISO as appropriate in carrying out its responsibilities under FAC-014-2.

4. Modeling

Applicable standards: MOD-031-2; MOD-032-1; .MOD-033-1 (when applicable and enforceable) and/or any successor standard(s) subject to enforcement.

SCE will provide to CAISO SCE's transmission system load and modeling data pursuant to the requirements from MOD-032-1 in accordance with the document entitled "CAISO & SCE Joint Transmission Planning Base Case Preparation Process", which is available on the caiso.com website. This document includes requirements from MOD-032-1 and the WECC Data Preparation Manual. The CAISO will include this data in its documentation for its Planning Coordinator Area and/or Balancing Authority Area, developed consistent with the NERC MOD-031-1 and MOD-032-1 Standards, and the CAISO Tariff and BPMs, that identify the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for MOD-031-1 and for MOD-032-1 system modeling data for power system modeling and reliability analyses. The CAISO will use SCE's transmission system load and modeling data and models provided by SCE to meet CAISO's obligations under MOD-031-1 and MOD-032-1 respectively. MOD-033-1 regarding steady-state and dynamic system model validation will become enforceable on 7/1/2017.

5. UFLs

Applicable standard and regional criteria: PRC-006-2; WECC Regional Criteria PRC-006-WECC-CRT-2; PRC-010-2 (when applicable and enforceable), and/or any successor standard(s) subject to enforcement..

SCE will participate in and/or provide information as necessary to WECC to be used as part of the WECC Off-Nominal Frequency Load Shedding Plan and for CAISO's studies and activities related to PRC-006-2 and WECC Regional Criteria PRC-006-WECC-CRT-2.

6. Transmission Relay Loadability

Applicable standard: PRC-023-3, and/or any successor standard(s) subject to enforcement.

CAISO will include SCE Facilities in its assessment required under PRC-023-3 Requirement R6 and its sub-requirements. Upon request, SCE will provide Facilities information as needed by CAISO to perform its PRC-023-3 Requirement R6 evaluation.

7. Nuclear

Applicable standard: NUC-001-3, and/or any successor standard(s) subject to enforcement.

NUC-001-3 is applicable to the CAISO and its Planning Coordinator Area, as the PG&E Diablo Canyon Nuclear Power Plant, located in PG&E's service area, is part of the California ISO Planning Coordinator Area. NUC-001-3 is no longer applicable to the SCE San Onofre Nuclear Generating Station (SONGS), which has been permanently closed. The permanent closure of SONGS was announced on June 7, 2013. SCE SONGS de-registered as a Nuclear Plant Generator Operator (NPGO) and was deactivated by NERC as a registered NPGO on November 13, 2013. Five requirements in a SONGS Switchyard Operation Letter Agreement, executed May 5, 2014 for the decommissioned SONGS, replaced the original 54 Nuclear Plant Interface Requirements and the SONGS NUC-001-2 Coordination Agreement. On May 19, 2014, FERC approved the amendment to the Transmission Control Agreement Appendix E for SONGS, effective June 1, 2014. It should be noted that the California ISO is not the Planning Coordinator for the Palo Verde Nuclear Power Plant, and the Palo Verde Nuclear Power Plant is not located within the California ISO's Planning Coordinator Area.

Attachment 3

[Following page]

Long Term Transmission Planning Process (LTTP) Cost

As of 10/20/2016

2015 GMC update meeting April 17, 2014 Cost of service Study

http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=72F94714-E777-4666-96B5-2948F249F67C

Exhibit 2 - 2013 Cost of Service Study Summary

http://www.caiso.com/Documents/Exhibit2-2013Cost-ServiceStudySummaryMar6_2014.pdf

Cost of the Long Term Transmission Planning Process

ABC Level 2 Activities ($ in thousands) all in Systems Operations	Code	System Operations	Indirect	Amount	LTPP Factor	Allocation to LTPP
From Page 2 - 2013 ABC Level 2 Direct Costs						
Develop Infrastructure (DI)	**80001**					
Regulatory contract procedures	201		100%	$ 378	0%	$ -
Manage Generator Interconnection Proceedures (GIP) agreements	202	100%		$ 818	0%	-
Manage GIP	203	100%		$ 2,342	0%	-
Long Term Transmission Planning process	**204**	**100%**		**$ 4,273**	**50%**	**$ 2,137**
New transmission resources	205	100%		$ 552	0%	-
Transmission maintenance studies	206	100%		$ 499	0%	-
Load resource data	207	100%		$ 268	0%	-
Season assessment	208	100%		$ 223	0%	-
Queue management	208	100%		$ 615	0%	-
Annual delivery assessment	210	100%		$ 25	0%	-
Total Long Term Transmission Planning process direct costs (activity 204 = $4,273 x factor of 50%)				**$ 9,993**		**$ 2,137**
From Page 1 - 2013 Revenue Requirement using 2013 ABC Data						
Total System Operations Costs before allocation of indirect costs						$ 48,915
Percentage of Long Term Transmission Planning process costs to ABC level 2 Direct Costs ($2,137 / $48,915)						4.37%
Total System Operations Indirect Dollars Allocated						$ 88,809
Long Term Transmission Planning process allocated indirect costs (4.37% x $88,809)						**$ 3,879**
Total Long Term Transmission Planning process costs ($2,137 + $3,879)						**$ 6,015**

Annual Planning Coordinator Service Charge Calculation

Total number of transmission circuits in ISO 2014/2015 Transmission Plan	1,550
Total number of transmission circuits in Southern California Edison Power system	4
Long Term Transmission Planning process cost per transmission circuit in ISO 2014/2015 Transmission Plan_SCE (in actual dollars)	$ 3,881
Annual Planning Coordinator service charge (in actual dollars)	**$ 15,524**

Attachment 4

Notices

1. As to the CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION:

   Neil Millar
   Executive Director, Infrastructure Development
   California Independent System Operator Corporation
   Street: 250 Outcropping Way
   City / State / Zip: Folsom, CA 95630
   Phone: (916) 608-1113
   Email: nmillar@caiso.com

2. As to SCE:

   Nestor Martinez
   Vice President, Engineering & Technical Services
   Southern California Edison Company
   Street: 2244 Walnut Grove Avenue
   City / State / Zip: Rosemead, CA 91770
   Phone: (626) 302-1063
   Email: Nestor.Martinez@sce.com

Redacted Pursuant to 18 C.F.R. § 388.112

This Document Contains Critical Energy Infrastructure Information

<u>DO NOT DISTRIBUTE</u>

Attachment B – CONFIDENTIAL Clean Tariff Sheets

Planning Coordinator Agreement between the

California Independent System Operator Corporation and

Southern California Edison

Attachment C – Declaration of April Gordon

Planning Coordinator Agreement between the

California Independent System Operator Corporation and

Southern California Edison

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER17-___-000**

DECLARATION OF APRIL GORDON ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I, April Gordon, state as follows:

1. I am employed as Director of Financial Planning and Procurement for the California Independent System Operator Corporation (the "CAISO"). My business address is 250 Outcropping Way, Folsom, California 95630. I am responsible for the CAISO's budget preparation and management; long term planning; corporate procurement and contract management. As part of my duties at the CAISO, I oversee the development of the CAISO's grid management charge.

2. I participated in the creation of the "California ISO – 2015 GMC Update Cost of Service Study – April 2, 2014", attached as Exhibit 1 to my declaration, and the spreadsheets calculating estimated costs that the CAISO will incur to provide planning services to Southern California Edison ("SCE") under the Planning Coordinator Agreement between the CAISO and SCE, attached as Exhibit 2 to my declaration.

3. To the best of my knowledge, the information provided in Exhibits 1 and 2 is a true and accurate description and estimate of the costs that the

CAISO will incur in providing planning services to SCE, under the Planning Coordinator Agreement between the CAISO and SCE, in 2017 for each billing unit identified.

I hereby certify under penalty of perjury that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on: March 16, 2017

/s/ April Gordon
April Gordon

Exhibit 1 to the Declaration of April Gordon

California ISO

2015 GMC Update
Cost of Service Study

April 2, 2014

Table of Contents

Executive Summary

The revenue requirement limit established by the ISO and developed with stakeholders during the 2012 grid management charge (GMC) stakeholder initiative and budget process will expire on December 31, 2014. According to tariff section 11.22.2.5, the ISO is required to seek Federal Energy Regulatory Commission (FERC) approval of another revenue requirement maximum for the period beginning January 1, 2015. To determine whether changes should be made to the revenue requirement cap or the GMC structure, the ISO has updated its 2012 cost of service analysis, which was based on 2010 costs, for 2015 and beyond.

By way of background, the ISO implemented activity based costing (ABC) in 2010, which was utilized for the 2012 cost of service study to restructure the GMC rate design. The new GMC design was vetted through a comprehensive stakeholder process and approved by the ISO Board of Governors (ISO Board) and FERC in 2011 to be effective on January 1, 2012. The structure contains three cost categories: market services, system operations and congestion revenue rights (CRR) services and percentages that are applied to the revenue requirement to determine the amount in the three cost categories upon which rates are set. The market services charge code is designed to recover costs the ISO incurs for running the markets. The system operations charge code is designed to recover costs the ISO incurs for reliably operating the grid in real time. The CRR charge code recovers costs the ISO incurs for running the CRR markets.

The updated 2015 cost of service analysis uses 2013 data to determine the percentages for the three cost categories, as reflected in the table below and is summarized in Exhibit 2. This cost of service analysis also updated the energy imbalance market (EIM) and transmission ownership rights (TOR) rates. The ISO has posted the EIM rate update development and the TOR rate update development in the other papers posted at the same time as this cost of service update.

Summary of Cost Category Percentages

Cost Category Percentages from Cost of Service Studies	2010 Study effective for 2012	2013 Study to effective for 2015	Change
Market Services	27%	**27%**	-
System Operations	69%	**70%**	1%
CRR Services	4%	**3%**	(1%)

The 2012 Cost of Service Study Overview and Activity Based Costing (ABC)

On September 30, 2011, FERC approved the ISO's redesigned GMC with an effective date of January 1, 2012.[1] As part of the 2012 GMC stakeholder initiative that led up to the FERC submission, the ISO conducted a cost of service study based, for the first time, on the recently implemented Activity Based Costing (ABC) model (2012 cost of service study), using 2010 ISO costs.[2] The ISO then used the 2012 cost of service study to calculate the cost allocation percentages assigned to the three cost of service "buckets": market services, system operations and CRR services, as well as the associated fees including the TOR fee.

This 2015 cost of service study uses the same ABC modeling and cost allocation methodology used to calculate the cost allocation percentages and TOR fee. However, the 2015 cost of service study updates the 2012 analysis by using 2013 data and also incorporates changes to the level 1 and 2 ABC processes that the ISO has made since the 2012 cost of service study. As discussed in more detail below, the ISO in 2011 completed its implementation of all ABC level 2 processes. At the start of 2013, ABC encompassed nine level 1 processes that align with the ISO's core business processes (see chart below). These processes were then broken down into 153 level 2 activities that align with a level 1 process and are a granular breakdown of the core business functions. See Exhibit 1 for a description of the ISO business process framework overview.

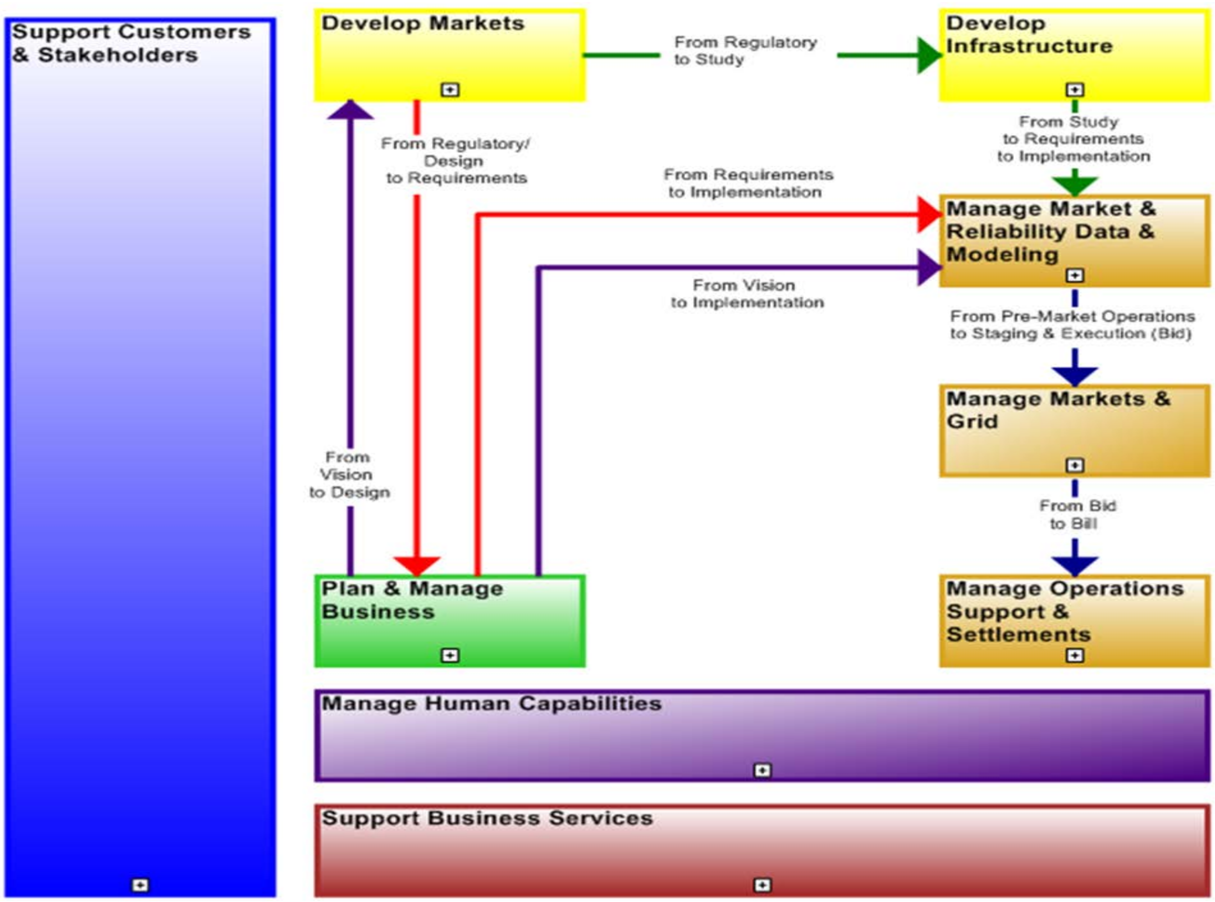
[1] See *California Independent System Operator Corp.* 136 FERC ¶61,236 (2011).
[2] The 2012 cost of service study can be found at: http://www.caiso.com/Documents/2012Cost-ServiceStudyDiscussionPaperwithExhibits.pdf

Application of ABC to GMC Structure

When the ISO, in 2010, conducted the 2012 cost of service study, time reporting for ABC level 1 activities had just been implemented. Full level 2 reporting, using activity codes and time sheet reporting, commenced in 2011 and has now been completed. This process is continually being reviewed and developed, and changes in definitions and levels have occurred since the 2012 cost of service study.

Currently, the ABC analysis has disaggregated the ISO into nine core processes (level 1 activities). Each of the core activities were further broken down into major processes (level 2 activities) that were mapped to the level one activity.

Mapping of ISO Core Business Processes



The level 2 processes discussed in this study are mapped and defined as of January 1, 2013. The level 1 activities can be categorized into two types: (1) direct operating costs —

those that can be directly mapped to a market, grid service or customer; and (2) support or indirect costs — those that support the direct activity.

Table 1 — Level 1 ABC Activities

Level 1 ABC Activity	Direct or support cost	Number of Level 2 activity codes	Level 1 Charge Code
Develop Infrastructure	Direct operating cost	11	80001
Develop Markets	Direct operating cost	9	80002
Manage Market and Reliability Data and Modeling	Direct operating cost	21	80004
Manage Market and Grid	Direct operating cost	13	80005
Manage Operations Support and Settlements	Direct operating cost	19	80006
Support Customers and Stakeholders	Direct operating cost	11	80010
Plan and Manage Business	Support costs	15	80008
Support Business Services	Support costs	46	80009
Manage Human Capabilities	Support costs	8	80003

Mapping of ABC Direct Operating Activities

These activities are defined, linked to specific processes, and measurable. Using the three GMC categories, the level 2 activities were mapped as either (1) all in one category or not in the category (100% or 0%); (2) a split between two categories (50% / 50%); or (3) partially in one category or another (80% or 20%) — or in the case of CRRs, a small portion of the activity (10%).

Table 2 — Mapping of ABC Direct Operating Activities to Cost Categories

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Definitions used in allocation		100%				the costs are entirely to support the market results and function resulting in a financially binding schedule or ancillary servicer award
			100%			the costs are entirely to support system operations
				100%		the costs are entirely to support the CRR process
					100%	Attributes are not distinguishable to any specific category
		50%	50%			the costs support equally both market and system operations
		45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
		80%	20%			the costs are predominantly market related but have some operational relationship
		20%	80%			the costs are predominantly operational flow based but have some market relationship
Develop Infrastructure (DI) (80001)						

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Regulatory contract procedures	201				100%	Attributes are not distinguishable to any specific category
Manage generation interconnection project (GIP) agreements	202		100%			managing the building and maintaining of the grid thus the costs are entirely to support system operations
Manage GIP	203		100%			
Long-term transmission planning	204		100%			
New transmission resources	205		100%			
Transmission maintenance studies	206		100%			
Load resource data	207		100%			
Seasonal assessment	208		100%			
Queue management	209		100%			
Annual delivery assessment	210		100%			
Develop Markets (DM) (80002)						
Manage tariff amendments	227				100%	Attributes are not distinguishable to any specific category
Post-order rehearing comp	228				100%	
State / Federal regulatory policy	229				100%	
Business process manual change management process	230				100%	
Develop infrastructure policy	231		100%			managing the building and maintaining of the grid thus the costs are entirely to support system operations
Perform market analysis	232	100%				the costs are entirely to support the market results & function
Develop market design	233	100%				
Regulatory contract negotiations	234				100%	Attributes are not distinguishable to any specific category
Manage Market and Reliability Data and Modeling (MMR) (80004)						
Manage full network model (FNM) maintenance	301	50%	50%			the costs support equally both market and system operations
Plan and develop operations simulator training	302	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
ISO meter certification	303		100%			measuring flows on the grid thus the costs are entirely to support system operations
Energy measure acquisition and analysis (EMMAA) telemetry	304		100%			measuring flows on the grid thus the costs are entirely to support system operations
Metering system configuration for market resources	305		100%			
Manage CRRs	307			100%		the costs are entirely to support the CRR process
Manage credit and collateral	308	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Resource management	309	50%	50%			resource attributes that support both thus the costs support equally both market and system operations
Manage reliability requirements	310		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage operations planning	311		100%			
Manage WECC seasonal studies	312		100%			
Participating intermittent resource projects (PIRP)	313	20%	80%			significantly more operational procedures, thus the costs are predominantly

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Manage & facilitate procedure maintenance	314	20%	80%			operational flow based but have some market relationship
Procedure administration and reporting	315	20%	80%			
Plan and develop operations training	316	20%	80%			
Execute and track operations training	317	20%	80%			
California Electric Training Advisory Committee (CETAC) activities	318		100%			relates to actual system operations thus the costs are entirely to support system operations
Provide stakeholder training	320				100%	Attributes are not distinguishable to any specific category
SC management	321				100%	
Manage Markets and Grid (MMG) (80005)						
Manage day ahead (DA) market support	352	100%				the costs are entirely to support the market results & function
Operations real time (RT) support	353	50%	50%			the costs support equally both market and system operations
Outage model and management	355		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage DA market	358	50%	50%			while managing market it results in system starting point for operational flows thus the costs support equally both market and system operations
Manage pre and post scheduling	359		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage operations engineering support	362	20%	80%			based on support of DA and RT thus the costs are predominantly operational flow based but have some market relationship
RT market – shift supervisor – manage post DA and pre RT	363	50%	50%			the costs support equally both market and system operations
RT Operations – generation and RT renewables coordinator (GRC) desks - maintain balancing area and manage RT pre dispatch	364	20%	80%			based on support of DA and RT thus the costs are predominantly operational flow based but have some market relationship
RT Operations – transmission desk – manage transmission and electric system	365		100%			relates to actual system operations thus the costs are entirely to support system operations
RT Operations – scheduling desk – manage RT interchange scheduling	366		100%			
Manage Operations Support and Settlements (MOS) (80007)						
Manage price validation & corrections	401	50%	50%			related to proper outage allocation thus the costs support equally both market and system operations
Manage dispute analysis & resolution	402				100%	Attributes are not distinguishable to any specific category
Manage the market quality system (MQS)	403	50%	50%			portion of MQS relates to operational flows thus the costs support equally both market and system operations
Manage data requests	404				100%	Attributes are not distinguishable to any specific category
Manage regulation no pay & deviation penalty calculations	405		100%			measuring actual performance thus the costs are entirely to support system operations
Manage rules of conduct	406				100%	Attributes are not distinguishable to any specific category

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Periodic meter audits	407		100%			measuring actual performance thus the costs are entirely to support system operations
ISO remote intelligence gateway (RIG) engineering	408		100%			
Manage energy measurement acquisition & analysis	409		100%			
Manage market clearing	411	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market billing & settlements	412	45%	45%	10%		
Manage reliability must run (RMR) settlements	413		100%			Supports reliability on the grid thus the costs are entirely to support system operations
Manage settlements release cycle	414	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market performance	417	50%	50%			the costs support equally both market and system operations
Manage dispute analysis and resolution	418				100%	Attributes are not distinguishable to any specific category
Perform market validation	419	50%	50%			the costs support equally both market and system operations
Support Customers and Stakeholders (SCC) (80010)						
Represent ISO externally	539				100%	Attributes are not distinguishable to any specific category
Client inquiries	601				100%	
Account management	602				100%	
Stakeholder processes	603				100%	
Develop participating transmission owners	605		100%			managing the building and maintaining of the grid thus the costs are entirely to support system operations
Service new clients	606				100%	Attributes are not distinguishable to any specific category
Government affairs	609				100%	Attributes are not distinguishable to any specific category
Communications and public relations	610				100%	

Allocation of Debt Service and Capital

Debt service is the aggregation of principle, interest, and a 25 percent debt service reserve on the 2008 and 2009 bonds. The debt service is the capital spent on projects over the last six years because the 2008 bonds rolled up the 2004, 2006 and 2007 bonds. The assets funded were broken down into operations related software, general software and fixed assets. The 2009 bonds funded the corporate headquarters so the debt service was allocated 100 percent to indirect. The revenue requirement also includes cash funded capital. The funds raised from the GMC go to maintaining a long term capital reserve fund, which varies from the capital project budget for that year. The number of and cost for capital projects vary significantly from year to year. The annual budget approves the spending limits for capital but not the projects themselves. A proposed listing is provided but the actual projects are subject to review and approval by an internal management committee as needed during the year. Because of the uncertainty of the actual projects coming on line, 100 percent of the cash funded capital will be allocated to indirect.

Table 3 — Allocation of Debt Service and Capital to GMC Cost Categories

Allocation of Debt Service and Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
2008 Bond Debt Service					
Operations Related Software					
Automated Dispatch System (ADS)		100%			RT instructions from market to system operations thus the costs are entirely to support system operations
Automated Load Forecast System (ALFS)	50%	50%			market & operations both need forecasts thus the costs support equally both market and system operations
CRR			100%		the costs are entirely to support the CRR process
DMM & compliance tools (SAS MARS)	50%	50%			the costs support equally both market and system operations
Energy Management System (EMS)		100%			the costs are entirely to support system operations
Existing Transmission Contracts Calculator (ETCC)		100%			This is a balancing authority responsibility
FNM / State estimator	50%	50%			Needed for market and system operations thus the costs support equally both market and system operations
Integrated Forward Market (IFM)	50%	50%			results support both financially binding schedules and system operations thus the costs support equally both market and system operations
MQS	50%	50%			aligns with direct operating process thus the costs support equally both market and system operations
Master file	50%	50%			
Meter Data Acquisition System (MDAS)		100%			data feed reflecting settling actual flow of systems operations performance thus the costs are entirely to support system operations
New Resource Interconnection (RIMs)	20%	80%			based on staff training for market services & system operations thus the costs are predominantly operational flow based but have some market relationship
Open Access Same Time Information System (OASIS)	50%	50%			the costs support equally both market and system operations
Operational Meter Analysis & Reporting (OMAR)		100%			same as MDAS thus the costs are entirely to support system operations
PIRP	20%	80%			based on staff training for market services & system operations thus the costs are predominantly operational flow based but have some market relationship
Portal	50%	50%			the costs support equally both market and system operations
CAISO Market Results interface (CMRI)	50%	50%			
Process Information System (PI)		100%			the costs are entirely to support system operations
RT markets	20%	80%			support & provide actual dispatches to balance system thus the costs are predominantly operational flow based but have some market relationship
HA Scheduling Protocol (HASP)	50%	50%			includes market power mitigation thus the costs support equally both market and system operations
Resource Adequacy	50%	50%			The costs support equally both market and system operations
RMR application Validation Engine (RAVE)	50%	50%			
Scheduling & Logging for ISO CA (SLIC)	50%	50%			

Allocation of Debt Service and Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
Control Area Scheduler (CAS)		100%			This is a balancing authority responsibility
Scheduling Infrastructure Business Rules (SIBR)	50%	50%			This contains interface to operations thus the costs support equally both market and system operations
Settlements & Market Clearing (SaMC)	15%	75%	10%		Based on DA and RT charge codes which settle 12 intervals operations hour for operations versus hourly for market thus after a minimum allocation to CRRs the costs are predominantly operational flow based but have some market relationship
General Software and Fixed Assets					
Client relations & engineering analysis tools				100%	Attributes are not distinguishable to any specific category
Local Area Network (LAN), WAN & monitoring (Tivoli)				100%	
Office automation desktop laptop (OA)				100%	
Oracle Corporate Financials				100%	
Security External Physical & ISS (CUDA)				100%	
Storage (EMC symmetrix)				100%	
Land and feasibility studies				100%	
NT servers and WEB servers				100%	
New system equipment				100%	
Office equipment, physical facilities software, furniture & leasehold improvements				100%	
2009 Bond Debt Service					
Iron Point headquarters				100%	Attributes are not distinguishable to any specific category
Cash Funded Capital					
Capital Project fund				100%	Amounts and projects vary yearly thus attributes are not distinguishable to any specific category

Allocation of Non-Payroll Support Costs

For the next step, significant non-payroll costs were pulled out of the operations and maintenance budget and allocated to buckets based on specific charge codes or to indirect costs. (see Table 4 next page)

Table 4 — Allocation of Non-Payroll Support Costs to GMC Cost Categories

Allocation of Non-Payroll Support Costs to GMC Cost Categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
Technology Division					
Hardware and software maintenance and leases				100%	Attributes are not distinguishable to any specific category
Communications (AT&T)				100%	
Occupancy costs				100%	
Operations Division					
PIRP forecasting costs	20%	80%			Use 80004 activity 313
General Counsel and Administrative Services Division					
Outside legal fees, financial audits and bank fees				100%	Attributes are not distinguishable to any specific category
SSAE 16 audit	45%	45%	10%		Use 80007 activity 412
Operational assessment	TBD	TBD			To be based on total % for 80005
Insurance				100%	Attributes are not distinguishable to any specific category

Allocation of ABC Support activities

The ABC support activities were allocated to indirect.

Table 5 — Allocation of ABC Support activities to GMC Cost Categories

Allocation of ABC support activities to GMC Cost Categories						
System	**Cost Code**	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category					
Plan and manage business	80008				100%	Attributes are not distinguishable to any specific category
Support business services	80009				100%	
Manage human capabilities	80003				100%	

Allocation of Other Income and Operating Reserve Credit

The remaining revenue requirement components, other income and operating reserve credit, were then analyzed and allocated to buckets based on specific charge codes or to indirect costs.

Table 6 — Allocation of Other Income to GMC Cost Categories

Allocation of Other Income to GMC Cost Categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
SC application fee				100%	Hardware and software maintenance and leases
MSS penalties				100%	
SC training fees				100%	
PIRP forecasting fees	20%	80%			Use 80004 activity 313
LGIP study fees		100%			Use 80001 activity 203
Interest				100%	Hardware and software maintenance and leases
COI path operator fees	TBD	TBD			To be based on total %s from 80005

Table 7 — Allocation of Operating Reserve Revenue Credit to GMC Cost Categories

Allocation of Operating Reserve Revenue Credit to GMC Cost Categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
Change in operations and maintenance budget				100%	Hardware and software maintenance and leases
25% debt service reserve on 2008 bonds	TBD	TBD	TBD	TBD	Based on %s from 2008 bonds debt service allocation
25% debt service reserve on 2009 bonds				100%	Hardware and software maintenance and leases
Revenue changes				100%	
Expense changes				100%	

Indirect Costs

Indirect costs are aggregated and then allocated proportional to direct costs. After this mapping is completed it can be applied to the ISO revenue requirement to derive the related cost of service.

Costing the 2013 Revenue Requirement

The allocation matrix of level 2 activities and software was applied to the ISO's 2013 revenue requirement (based on the budget approved by the ISO Board in December 2012) to determine the costs associated with three categories: market services, system operations and CRR services. The 2013 revenue requirement data and employee hours are the most recent information available to both determine the GMC cost category percentage updates and the updated revenue requirement for the ISO's 2015 GMC tariff filing.

Table 8 — Components of the 2013 revenue requirement:

Revenue Requirement	2013 Budget ($ in thousands)
Operating and maintenance costs	$ 162,907
Debt service 2008 bonds	24,666
Debt service 2009 bonds	17,847
Cash funded capital	24,000
Other income	(7,900)
Operating reserve	(25,492)
Total Revenue Requirement	**$ 196,028**

Completing the analysis required the following steps:

1. Breaking out non-ABC Operating and maintenance (O&M) support costs and applying cost category percentages to these costs;
2. Mapping the ABC direct and support O&M costs into two components: level 2 activities and support costs. This process involved:
   a. allocating cost centers to level 1 ABC activities
   b. applying cost category percentages to level 1 support costs
   c. obtaining time estimates for level 2 activities for those level 1 activities that are direct operating costs
   d. allocating costs to level 2 activities
   e. applying cost category percentages;
3. Mapping remaining revenue requirements to cost categories and applying cost category percentages to these costs;
4. Aggregating costs and allocating indirect costs to cost categories based on percentage of direct costs, allocating fees to the three buckets and determining resulting cost category percentages; and
5. Dividing resulting costs by estimated volumes to determine 2013 rates using revised cost category percentages.

Step 1: Breaking Out Non-ABC Support Costs

There are two types of O&M costs; those that are activity related such as costs attributed to personnel, and non-ABC costs such as facilities costs. The O&M budget was broken down into those two categories. The significant non-ABC support costs were removed from the divisions and allocated separately.

Table 9 — Mapping Costs to ABC Activities and Non-ABC Support Costs

Mapping Costs to Direct and Support Activities and Non-ABC Support Costs		2013 Budget ($ in thousands)		
Division		Total	ABC Activities	Non-ABC
Chief Executive Officer	2100	$ 4,589	$ 4,589	$ -
Market and Infrastructure Development	2200	13,991	13,991	
Technology	2400	58,653	38,319	20,334
Operations	2500	42,724	42,021	703
General Counsel and Administrative Services	2600	27,070	19,234	7,836
Market Quality and Renewable Integration	2700	5,871	4,887	984
Policy and Client Services	2800	10,009	10,009	
Total		**$ 162,907**	**$ 133,050**	**$ 29,857**

These budgeted costs were allocated using the percentages shown in *Table 4 — Allocation of Non-Payroll Support Costs to GMC Cost Categories.*

Table 10 — Allocation of Non-ABC Support to Cost Categories

Allocation of Non-ABC support costs									
Non-ABC support costs	Market Services	System Operations	CRRs	Indirect	2013 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Technology Division									
Hardware and software maintenance and leases				100%	$ 8,941	$ -	$ -	$ -	$ 8,941
Communications (AT&T)				100%	5,952				5,952
Occupancy costs				100%	5,441				5,441
Operations Division									
PIRP forecasting costs	20%	80%			1,687	337	1,350		
General Counsel and Administrative Services Division									
Outside legal fees, financial audits and bank fees				100%	5,180				5,180
SSAE 16 audit	45%	45%	10%		539	243	243	53	
Operational assessment	17%	83%			200	34	166		
Insurance				100%	1,917				1,917
Total					**$ 29,857**	**$ 614**	**$ 1,759**	**$ 53**	**$ 27,431**

Step 2: Allocation of O&M Costs

For activity related O&M costs, the recent ABC structure was utilized to allocate costs between the cost categories. ISO activities have been broken out into nine level 1 ABC activities as shown in *Table 1 — Level 1 ABC Activities*. For those direct operating level 1 activities, the associated level 2 activities were mapped to one of the three cost categories as shown in *Table 2 — Mapping of ABC Level 2 Direct Operating Activities to Cost Categories.* The level 1 support activities were allocated to ABC support costs.

The O&M budget is comprised of approximately 103 cost centers. As discussed above, ISO staff has been coding their time to ABC level 1 and level 2 activities since 2011. The time for 2013 was collected and the percentage breakdown of each cost center by the level one and level 2 direct activities was determined. The percentage was applied to the activity budget for the cost center to allocate the cost center activity budget by dollars to the level one and level 2 direct operating activities.

ABC Direct Operating Activities

Table 11 — Mapping Division Hours to Direct Operating Activities

Mapping Division Hours to Direct Operating activities	Percentage of time related to direct operating activities					
	Develop infra-structure (DI)	Develop markets (DM)	Manage market and reliability and data modeling (MMR)	Manage markets and Grid (MMG)	Manage operations support and settlements (MOS)	Support customers and stake-holders (SCS)
Organization Name	**80001**	**80002**	**80004**	**80005**	**80007**	**80010**
Chief Executive Officer (CEO)						
Market and Infrastructure Development (MID)	74%	20%	2%			
Technology (Tech)			4%	3%	1%	
Operations (Ops)			21%	53%	18%	
General Counsel and Administrative Services (GCAS)		2%	4%		1%	
Market Quality and Renewable Integration (MQRI)	3%	46%	3%	6%	33%	
Policy and Client Services (PCS)			7%			87%
Total	**8%**	**4%**	**9%**	**19%**	**7%**	**6%**

The hours were aggregated by level 2 activity.

Table 12 — Mapping Division hours to level 2 activities

		ISO Divisions							
ABC Level 2 Activities	Cost Code	CEO 2100	MID 2200	Tech 2400	Ops 2500	GCAS 2600	MQRI 2700	PCS 2800	Total
Develop Infrastructure (DI) (80001)									
Regulatory contract procedures	201		100%						4%
Manage GIP agreements	202		100%						8%
Manage GIP	203		98%			2%			27%
Long-term transmission planning	204		100%						42%
New transmission resources	205		100%						3%
Transmission maintenance studies	206		100%						4%
Load resource data	207		100%						3%
Seasonal assessment	208		100%						3%
Queue management	209		100%						6%
Annual delivery assessment	210		100%						
Total			99%			1%			100%
Develop Markets (DM) (80002)									
Manage tariff amendments	227					100%			6%
Post-order rehearing comp	228		100%						1%
State / Federal regulatory policy	229		86%		14%				10%
Business process manual change management process	230		15%					85%	1%
Develop infrastructure policy	231		100%						14%
Perform market analysis	232						100%		28%
Develop market design	233						18%		38%
Regulatory contract negotiations	234		82%						2%
Total			59%		1%	6%	34%		100%
Manage Market & Reliability Data & Modeling (MMR) (80004)									
Manage FNM maintenance	301			74%	22%		4%		14%
Plan and develop operations simulator training	302			10%	90%				3%
ISO meter certification	303				100%				4%
EMMAA telemetry	304				100%				1%
Metering system configuration for market resources	305				100%				1%
Manage CRRs	307				100%				5%
Manage credit and collateral	308					100%			6%
Resource management	309				96%		4%		9%
Manage reliability requirements	310		38%		57%		5%		9%
Manage operations planning	311				96%		4%		13%
Manage WECC seasonal studies	312				100%				1%
PIRP	313				100%				
Manage & facilitate procedure maintenance	314				100%				8%
Procedure administration and reporting	315				100%				
Plan and develop operations training	316				95%		5%		7%
Execute and track operations training	317				97%		3%		13%
CETAC activities	318				100%				1%
Provide stakeholder training	320							100%	3%
SC management	321							100%	2%
Total			3%	12%	72%	6%	3%	4%	100%
Manage Markets and Grid (MMG) (80005)									

ABC Level 2 Activities	Cost Code	ISO Divisions CEO 2100	MID 2200	Tech 2400	Ops 2500	GCAS 2600	MQRI 2700	PCS 2800	Total
Manage DA market support	352			94%	6%				
Operations RT support	353			57%	20%		23%		5%
Outage model and management	355				100%				11%
Manage DA market	358				100%				10%
Manage pre and post scheduling	359				100%				4%
Manage operations engineering support	362				100%				4%
RT market – shift supervisor – manage post DA and pre RT	363				100%				8%
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364				100%				24%
RTO – transmission desk – manage transmission and electric system	365				100%				19%
RTO – scheduling desk – manage RT interchange scheduling	366				100%				15%
Total				3%	96%		1%		100%
Manage Operations Support & Settlements (MOS) (80007)									
Manage price validation & corrections	401			20%	80%				2%
Manage dispute analysis & resolution	402			2%	98%				10%
Manage MQS	403			13%	87%				16%
Manage data requests	404				100%				2%
Manage regulation no pay & deviation penalty calculations	405				100%				
Manage rules of conduct	406				100%				2%
Periodic meter audits	407				100%				
ISO RIG engineering	408				100%				5%
Manage energy measurement acquisition & analysis	409				100%				12%
Manage market clearing	411					100%			2%
Manage market billing & settlements	412				96%	4%			17%
Manage RMR settlements	413				100%				
Manage settlements release cycle	414				100%				11%
Manage market performance	417						100%		3%
Manage dispute analysis and resolution	418							100%	
Perform market validation	419			1%	14%		85%		17%
Total				3%	78%	2%	17%		100%
Support Customers and Stakeholders (SCC) (80010)									
Represent ISO externally	539		16%	40%	1%	29%	7%	7%	3%
Client inquiries	601							100%	14%
Account management	602							100%	10%
Stakeholder processes	603							100%	7%
Develop participating transmission owners	605							100%	
Service new clients	606							100%	3%
Government affairs	609							100%	43%
Communications and public relations	610							100%	20%
Total						1%		98%	100%
Direct O&M			**19%**	**5%**	**57%**	**2%**	**6%**	**11%**	**100%**

These costs were inputs into the allocation matrix shown in *Table 2 — Mapping of ABC Level 2 Direct Operating Activities to Cost Categories* to get the costs to the cost categories.

Table 13 — Allocation of Division Costs to Direct Operating Activities

Mapping costs to direct and support activities & Other costs	Allocation of direct operating costs ($ in thousands)						
	Develop infra-structure (DI)	Develop markets (DM)	Manage market and reliability and data modeling (MMR)	Manage markets and Grid (MMG)	Manage operations support and settlements (MOS)	Support customers and stake-holders (SCS)	Direct operating activities
Organization Name	**80001**	**80002**	**80004**	**80005**	**80007**	**80010**	**Total**
Chief Executive Officer (CEO)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market and Infrastructure Development (MID)	9,726	3,340	352		3	37	13,458
Technology (Tech)	26		1,305	802	215	99	2,447
Operations (Ops)	3	79	7,491	24,689	5,509	4	37,775
General Counsel and Administrative Services (GCAS)	62	355	583		153	65	1,218
Market Quality and Renewable Integration (MQRI)	176	1,997	293	286	1,229	16	3,997
Policy and Client Services (PCS)		28	452		24	8,965	9,469
Total	**$ 9,993**	**$ 5,799**	**$ 10,476**	**$ 25,777**	**$ 7,133**	**$ 9,186**	**$ 68,364**

The costs were aggregated by level 2 activity.

Table 14 — Allocation of Division Costs to Level 2 activity

		ISO Divisions							
ABC Level 2 Activities	**Cost Code**	**CEO 2100**	**MID 2200**	**Tech 2400**	**Ops 2500**	**GCAS2 2600**	**MQRI 2700**	**PCS 2800**	**Total**
Develop Infrastructure (DI) (80001)									
Regulatory contract procedures	201	$ -	$ 378	$ -	$ -	$ -	$ -	$ -	$ 378
Manage GIP agreements	202		818						818
Manage GIP	203		2,251	26	3	62			2,342
Long-term transmission planning	204		4,273						4,273
New transmission resources	205		376				176		552
Transmission maintenance studies	206		499						499
Load resource data	207		268						268
Seasonal assessment	208		223						223
Queue management	209		615						615
Annual delivery assessment	210		25						25
Total			**9,726**	**26**	**3**	**62**	**176**		**9,993**
Develop Markets (DM) (80002)									
Manage tariff amendments	227					355			355
Post-order rehearing comp	228		30						30
State / Federal regulatory policy	229		485		79				564
Business process manual change management process	230		5					28	33
Develop infrastructure policy	231		829						829
Perform market analysis	232		2				1,602		1,604
Develop market design	233		1,847				395		2,242
Regulatory contract negotiations	234		142						142
Total			**3,340**		**79**	**355**	**1,997**	**28**	**5,799**
Manage Market & Reliability Data & Modeling (MMR) (80004)									

		ISO Divisions							
ABC Level 2 Activities	**Cost Code**	**CEO 2100**	**MID 2200**	**Tech 2400**	**Ops 2500**	**GCAS2 2600**	**MQRI 2700**	**PCS 2800**	**Total**
Manage FNM maintenance	301			1,274	377		73		1,723
Plan and develop operations simulator training	302			31	269				300
ISO meter certification	303				416				416
EMMAA telemetry	304				100				100
Metering system configuration for market resources	305				70				70
Manage CRRs	307				574				574
Manage credit and collateral	308					583			583
Resource management	309				875		35		910
Manage reliability requirements	310		352		535		44		930
Manage operations planning	311				1,262		59		1,322
Manage WECC seasonal studies	312				71				71
PIRP	313				1				1
Manage & facilitate procedure maintenance	314				841				841
Procedure administration and reporting	315				11				11
Plan and develop operations training	316				679		35		714
Execute and track operations training	317				1,336		47		1,384
CETAC activities	318				73				73
Provide stakeholder training	320							286	286
SC management	321							167	167
Total			**352**	**1,305**	**7,490**	**583**	**293**	**453**	**10,476**
Manage Markets and Grid (MMG) (80005)									
Manage DA market support	352			107	8				115
Operations RT support	353			695	250		286		1,231
Outage model and management	355				2,921				2,921
Manage DA market	358				2,564				2,564
Manage pre and post scheduling	359				974				974
Manage operations engineering support	362				1,148				1,148
RT market – shift supervisor – manage post DA and pre RT	363				2,021				2,021
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364				6,093				6,093
RTO – transmission desk – manage transmission and electric system	365				4,956				4,956
RTO – scheduling desk – manage RT interchange scheduling	366				3,754				3,754
Total				802	24,689		286		25,777
Manage Operations Support & Settlements (MOS) (80007)									
Manage price validation & corrections	401			31	125				156
Manage dispute analysis & resolution	402			16	709				725
Manage MQS	403			150	992				1,142
Manage data requests	404				97				97
Manage regulation no pay & deviation penalty calculations	405				8				8
Manage rules of conduct	406				165				165
Periodic meter audits	407				4				4
ISO RIG engineering	408				332				332
Manage energy measurement acquisition & analysis	409				926				926
Manage market clearing	411					111			111
Manage market billing & settlements	412				1,160	42			1,202
Manage RMR settlements	413				10				10

		ISO Divisions							
ABC Level 2 Activities	**Cost Code**	**CEO 2100**	**MID 2200**	**Tech 2400**	**Ops 2500**	**GCAS2 2600**	**MQRI 2700**	**PCS 2800**	**Total**
Manage settlements release cycle	414				807				807
Manage market performance	417						208		208
Manage dispute analysis and resolution	418							24	24
Perform market validation	419		3	18	175		1,020		1,216
Total			3	215	5,510	153	1,228	24	7,133
Support Customers and Stakeholders (SCC) (80010)									
Represent ISO externally	539		36	88	3	65	16	16	224
Client inquiries	601							1,318	1,318
Account management	602							889	889
Stakeholder processes	603				1			665	666
Develop participating transmission owners	605							8	8
Service new clients	606							299	299
Government affairs	609			10				3,979	3,989
Communications and public relations	610							1,793	1,793
Total			**36**	**98**	**4**	**65**	**16**	**8,967**	**9,186**
Direct O&M			**$ 13,458**	**$ 2,447**	**$ 37,775**	**$ 1,218**	**$ 3,997**	**$ 9,469**	**$ 68,364**

For direct operating activities the costs were aggregated at level 2 and allocated to the cost category identified in *Table 2 — Mapping of ABC Level 2 Direct Operating Activities to Cost Categories.*

Table 15 — Mapping ABC Direct Operating Activities to Cost Categories

		ABC Direct Operating Activities								
ABC Level 2 Activities	**Cost Code**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
		% of costs allocated to activity				**Cost of category $ in thousands**				
Develop Infrastructure (DI) (80001)										
Regulatory contract procedures	201				100%	$ 378	$ -	$ -	$ -	$ 378
Manage GIP agreements	202		100%			818		818		
Manage GIP	203		100%			2,342		2,342		
Long-term transmission planning	204		100%			4,273		4,273		
New transmission resources	205		100%			552		552		
Transmission maintenance studies	206		100%			499		499		
Load resource data	207		100%			268		268		
Seasonal assessment	208		100%			223		223		
Queue management	209		100%			615		615		
Annual delivery assessment	210		100%			25		25		
Total DI						**9,993**		**9,615**		**378**
Develop Markets (DM) (80002)										
Manage tariff amendments	227				100%	355				355
Post-order rehearing comp	228				100%	30				30
State / Federal regulatory policy	229				100%	564				564
Business process manual change management process	230				100%	33				33
Develop infrastructure policy	231		100%			829		829		
Perform market analysis	232	100%				1,604	1,604			
Develop market design	233	100%				2,242	2,242			
Regulatory contract negotiations	234				100%	142				142

ABC Direct Operating Activities										
ABC Level 2 Activities	Cost Code	Market Services	System Operations	CRR Services	Indirect	2013 Budget	Market Services	System Operations	CRR Services	Indirect
		% of costs allocated to activity				Cost of category $ in thousands				
Total DM						**5,799**	**3,846**	**829**		**1,124**
Manage Market & Reliability Data & Modeling (MMR) (80004)										
Manage FNM maintenance	301	50%	50%			1,724	862	862		
Plan and develop operations simulator training	302	20%	80%			300	60	240		
ISO meter certification	303		100%			416		416		
EMMAA telemetry	304		100%			100		100		
Metering system configuration for market resources	305		100%			70		70		
Manage CRRs	307			100%		574			574	
Manage credit and collateral	308	45%	45%	10%		583	262	262	59	
Resource management	309	50%	50%			910	455	455		
Manage reliability requirements	310		100%			931		931		
Manage operations planning	311		100%			1,321		1,321		
Manage WECC seasonal studies	312		100%			71		71		
PIRP	313	20%	80%			1		1		
Manage & facilitate procedure maintenance	314	20%	80%			841	168	673		
Procedure administration and reporting	315	20%	80%			11	2	9		
Plan and develop operations training	316	20%	80%			714	143	571		
Execute and track operations training	317	20%	80%			1,383	277	1,106		
CETAC activities	318		100%			73		73		
Provide stakeholder training	320				100%	286				286
SC management	321				100%	167				167
Total MMR						**10,476**	**2,229**	**7,161**	**633**	**453**
Manage Markets and Grid (MMG) (80005)										
Manage DA market support	352	100%				115	115			
Operations RT support	353	50%	50%			1,231	616	615		
Outage model and management	355		100%			2,921		2,921		
Manage DA market	358	50%	50%			2,564	1,282	1,282		
Manage pre and post scheduling	359		100%			974		974		
Manage operations engineering support	362	20%	80%			1,148	230	918		
RT market – shift supervisor – manage post DA and pre RT	363	50%	50%			2,021	1,011	1,010		
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364	20%	80%			6,093	1,219	4,874		
RTO – transmission desk – manage transmission and electric system	365		100%			4,956		4,956		
RTO – scheduling desk – manage RT interchange scheduling	366		100%			3,754		3,754		
Total MMG						**25,777**	**4,473**	**21,304**	**-**	**-**
Total MMG %						**100%**	**17%**	**83%**		
Manage Operations Support & Settlements (MOS) (80007)										
Manage price validation and corrections	401	50%	50%			156	78	78		
Manage dispute analysis & resolution	402				100%	725				725
Manage MQS	403	50%	50%			1,142	571	571		
Manage data requests	404				100%	97				97
Manage regulation no pay & deviation penalty calculations	405		100%			8		8		

ABC Direct Operating Activities										
ABC Level 2 Activities	**Cost Code**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
		% of costs allocated to activity				**Cost of category $ in thousands**				
Manage rules of conduct	406				100%	165				165
Periodic meter audits	407		100%			4		4		
ISO RIG engineering	408		100%			332		332		
Manage energy measurement acquisition & analysis	409		100%			926		926		
Manage market clearing	411	45%	45%	10%		111	50	50	11	
Manage market billing & settlements	412	45%	45%	10%		1,202	541	541	120	
Manage RMR settlements	413		100%			10		10		
Manage settlements release cycle	414	45%	45%	10%		807	363	363	81	
Manage market performance	417	50%	50%			208	104	104		
Manage dispute analysis and resolution	418				100%	24				24
Perform market validation	419	50%	50%			1,216	608	608		
Total MOS						**7,133**	**2,315**	**3,595**	**212**	**1,011**
Support Customers and Stakeholders (SCC) (80010)										
Represent ISO externally	539				100%	224				224
Client inquiries	601				100%	1,318				1,318
Account management	602				100%	889				889
Stakeholder processes	603				100%	666				666
Develop participating transmission owners	605		100%			8		8		
Service new clients	606				100%	299				299
Government affairs	609				100%	3,989				3,989
Communications and public relations	610				100%	1,793				1,793
Total SSC						**9,297**		**8**		**9,297**
Total Direct O&M						**$ 68,364**	**$ 12,863**	**$ 42,512**	**$ 845**	**$ 12,144**
Direct O&M %						**100%**	**19%**	**62%**	**1%**	**18%**

ABC Support Activities

The same process yielded the following percentages for the three support activities.

Table 16 — Mapping Division Hours to Support Activities

Mapping support activities	Percentage of time related to support operating activities		
	Manage human capabilities (MHC)	Plan and manage business (PMB)	Support Business Services (SBS)
Organization Name	**80003**	**80008**	**80009**
Chief Executive Officer	0%	14%	86%
Market and Infrastructure Development	0%	0%	3%
Technology	0%	9%	83%
Operations	0%	1%	8%
General Counsel and Administrative Services	21%	7%	64%
Market Quality and Renewable Integration	0%	2%	7%
Policy and Client Services	0%	0%	5%
Total	**2%**	**5%**	**40%**

These costs were inputs into the allocation matrix shown in *Table 5 — Allocation of ABC Support activities to GMC Cost Categories* to get the costs to the cost categories.

Table 17 — Mapping Division Costs to Support Activities

Mapping support activities	Percentage of time related to support operating activities			
	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
Organization Name	**80003**	**80008**	**80009**	**Total**
Chief Executive Officer	$ -	$ 1,838	$ 2,751	$ 4,589
Market and Infrastructure Development			533	533
Technology		4,911	30,961	35,872
Operations	5	1,109	3,132	4,246
General Counsel and Administrative Services	4,918	1,891	11,207	18,016
16Market Quality and Renewable Integration		213	677	890
Policy and Client Services	1	11	528	540
Total	**$ 4,924**	**$ 9,973**	**$ 49,789**	**$ 64,686**

For support activities the costs were aggregated and allocated as shown in *Table 5 — Allocation of ABC Support activities to GMC Cost Categories.*

Table 18 — Mapping ABC Support Activities to Cost Categories

Allocation of ABC Support Activities									
ABC Level 1 Activities	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
Manage Human Capabilities (80003)				100%	$ 4,924				$ 4,924
Plan & Manage Business (80008)				100%	9,973				9,973
Support Business Services (80009)				100%	49,789				49,789
Total					**$ 64,686**				**$ 64,686**

Step 3 — Allocating Remaining Revenue Requirements to Cost Categories

Debt Service and Cash Funded Capital

The allocation of costs is based on the percentage allocation in *Table 3 — Allocation of Debt Service and Capital to GMC Cost Categories.* (see Table 19 below)

Table 19 — Mapping Debt Service and Cash Funded Capital to Cost Categories

Debt Service and Capital									
System	Market Services	System Operations	CRR Services	Indirect	2013 Budget	Market Services	System Operations	CRR Services	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Operations Related Software									
ADS		100%			$ 30	$ -	$ 30	$ -	$ -
ALFS	50%	50%			79	40	39		
CRRs			100%		855			855	
DMM & compliance Tools	50%	50%			478	239	239		
EMS		100%			1,923		1,923		
ETCC		100%			5		5		
FNM / State estimator	50%	50%			182	91	91		
IFM	50%	50%			6,365	3,183	3,182		
MQS	50%	50%			1,013	506	507		
Master file	50%	50%			409	205	204		
MDAS		100%			15		15		
NRI	20%	80%			219	44	175		
OASIS	50%	50%			66	33	33		
OMAR		100%			96		96		
PIRP	20%	80%			45	9	36		
Portal	50%	50%			473	236	237		
CMRI	50%	50%			411	206	205		
PI		100%			137		137		
RT market	20%	80%			1,271	254	1,017		
HASP	505	50%			1,270	635	635		
Resource Adequacy	50%	50%			43	21	22		
RAVE	50%	50%			5	3	2		
SLIC	50%	50%			295	147	148		
CAS		100%			47		47		
SIBR	50%	50%			1,801	900	901		
SaMC	15%	75%	10%		3,407	511	2,555	341	
Total operations related software					**20,940**	**7,263**	**12,481**	**1,196**	
General Software and Fixed Assets									
Client relations & engineering analysis tools				100%	154				154
LAN, WAN & monitoring				100%	650				650
OA				100%	80				80
Oracle Corporate Financials				100%	606				606
CUDA				100%	99				99
Storage				100%	889				889
Land & feasibility studies				100%	238				238
NT servers and WEB servers				100%	232				232
New system equipment				100%	400				400
Office equip, furniture and leasehold imp				100%	378				378
Total general software and fixed assets				**100%**	**4,204**	**239**	**239**		**3,726**
Total 2008 bond debt service $					**$ 24,666**	**$ 7,263**	**$ 12,481**	**$ 1,196**	**$ 3,726**
Total 2008 bond debt service %					**100%**	**29%**	**51%**	**5%**	**15%**

Debt Service and Capital									
System	Market Services	System Operations	CRR Services	Indirect	2013 Budget	Market Services	System Operations	CRR Services	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
2009 Bond debt service									
Iron Point headquarters				100%	**$ 17,847**				**$ 17,847**
Cash Funded Capital									
Capital Project fund				100%	**$ 24,000**				**$ 24,000**

Miscellaneous Revenue

The components of other revenue were reviewed and all revenues allocated pursuant to *Table 6 — Allocation of Other Income to GMC Cost Categories.*

Table 20 — Mapping Miscellaneous Revenue to Cost Categories

Allocation of Miscellaneous Revenue									
Type	Market Services	System Operations	CRR Services	Indirect	2013 Budget	Market Services	System Operations	CRR Services	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
SC application fee				100%	$ 100	$ -	$ -		$ 100
MSS penalties				100%	250				250
SC training fees				100%	150				150
Intermittent resource forecasting fee	20%	80%			1,600	320	1,280		
LGIP study fees		100%			2,000		2,000		
Interest				100%	1,800				1,800
COI path operator fees	17%	83%			2,000	340	1,660		
Total miscellaneous revenue					**$ 7,900**	**$ 660**	**$ 4,940**		**$ 2,300**

Operating Reserve Credit

The components of the operating reserve credit were reviewed and allocated pursuant to *Table 7 — Allocation of Operating Reserve Revenue Credit to GMC Cost Categories.* (see Table 21 below)

Table 21 — Mapping Reserve Credit to Cost Categories

Allocation of Operating reserve credit									
Type	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
Decrease in 15% reserve for O&M				100%	$ 21	$ -	$ -	$ -	$ 21
25% debt service reserve 2008 bonds	29%	51%	5%	15%	5,680	1,647	2,897	284	852
25% debt service reserve 2009 bonds				100%	3,570				3,570
Revenue changes				100%	9,266				9,266
Expense changes				100%	6,955				6,955
Total					**$ 25,492**	**$ 1,647**	**$ 2,897**	**$ 284**	**$ 20,664**

Step 4 — Aggregating Revenue Requirement into Cost Categories

The individual revenue requirements were aggregated and indirect costs allocated based on the total of direct costs. See Exhibit 2 for a summary of the cost of service study.

Table 22 — Mapping Revenue Requirement to Cost Categories

Revenue Requirement ($ in thousands)	2013 Budget	Market Services	System Operations	CRR Services	Indirect
Direct O&M $	$ 68,364	$ 12,863	$ 42,512	$ 845	$ 12,144
Support O&M $	64,686				64,686
Non-ABC support O&M $	29,857	614	1,759	53	27,431
Total O&M	**162,907**	**13,477**	**44,271**	**898**	**104,261**
Debt Service 2008 bonds	24,666	7,263	12,481	1,196	3,726
Debt Service 2009 bonds	17,847				17,847
Debt Service 2008 bonds	24,000				24,000
Total debt service and capital	**66,513**	**7,263**	**12,481**	**1,196**	**45,573**
Other income	(7,900)	(660)	(4,940)		(2,300)
Operating reserve	(25,492)	(1,647)	(2,897)	(284)	(20,664)
Total before allocation of indirect	**196,028**	**18,433**	**48,915**	**1,810**	**126,870**
Allocate indirect based on direct cost %		27%	70%	3%	
Allocate indirect		34,255	88,809	3,806	(126,870)
Total Revenue to Collect $	**$ 196,028**	**$ 52,688**	**$ 137,724**	**$ 5,616**	
Total Cost Category percentages	**100%**	**27%**	**70%**	**3%**	

Step 5 — Calculation of 2013 Rates Using New Cost Category Percentages

Although not necessary to determine the cost category percentages, the rates are needed to determine the EIM fee are covered in a separate paper and summarized in Exhibit 2. The GMC rates are determined by first estimating fees as shown in the following table.

Table 23 — Estimation of Fee Revenue and mapping of Fees to Cost Categories

Fee	Estimated 2013 volumes	Rate	Revenue (in thousands)	Cost Category
Bid segment fees	40,659,200	$0.005 per bid	$ 203	Market Services
Inter-SC trades	2,750,910	$1.00 per trade	2,781	
SCID fees	173	$1,000 per month	2,079	
TOR charges	3,679,322	$0.27 per MWh	993	System Operations
CRR auction bid fee	186,318	$1.00 per bid	186	CRR Services
Total Fees			**$ 6,242**	

Then the fees are deducted from the revenue requirement resulting in the remaining revenue requirement to collect. The remaining amount to collect is divided by the estimated volumes of billing determinants for each cost category to determine the respective rates.

Table 24 — 2013 GMC Rates Using Revised Cost Category Percentages

Revenue Requirement	2013 Budget	Market Services	System Operations	CRR Services
Revenue Requirement in thousands of $	**$ 196,028**	**$ 52,688**	**$ 137,724**	**$ 5,616**
Less Fees				
Bid segment fees	(203)	(203)		
Inter-SC trade fees	(2,781)	(2,781)		
SCID fees	(2,079)	(2,079)		
TOR charges	(993)		(993)	
CRR auction bid fees	(186)			(186)
Total fees	**(6,242)**	**(5,063)**	**(993)**	**(186)**
Remaining revenue requirement to collect	**$ 189,786**	**$ 47,625**	**$ 136,731**	**$ 5,430**
Estimated volumes in thousands of MWh		514,168	474,712	566,649
Less grandfathered contracts			(7,179)	
Estimated volumes		**514,168**	**467,533**	**566,649**
2013 rates using revised percentages		**$ 0.0926**	**$ 0.2925**	**$ 0.0096**

Summary of Cost Category Percentages

The results of the cost of service analysis for the cost category percentages that will go into effect in 2015 are as reflected in the following table.

Summary of Cost Category Percentages for 2015

Category	Percentage
Market Services	27%
System Operations	70%
CRR Services	3%

Exhibit 2 to the Declaration of April Gordon

Long Term Transmission Planning Process (LTTP) Cost

As of 10/20/2016

2015 GMC update meeting April 17, 2014 Cost of service Study

http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=72F94714-E777-4666-96B5-2948F249F67C

Exhibit 2 - 2013 Cost of Service Study Summary

http://www.caiso.com/Documents/Exhibit2-2013Cost-ServiceStudySummaryMar6_2014.pdf

Cost of the Long Term Transmission Planning Process

ABC Level 2 Activities ($ in thousands) all in Systems Operations	Code	System Operations	Indirect	Amount	LTPP Factor	Allocation to LTPP
From Page 2 - 2013 ABC Level 2 Direct Costs						
Develop Infrastructure (DI)	**80001**					
Regulatory contract procedures	201		100%	$ 378	0%	$ -
Manage Generator Interconnection Proceedures (GIP) agreements	202	100%		$ 818	0%	-
Manage GIP	203	100%		$ 2,342	0%	-
Long Term Transmission Planning process	**204**	**100%**		**$ 4,273**	**50%**	**$ 2,137**
New transmission resources	205	100%		$ 552	0%	-
Transmission maintenance studies	206	100%		$ 499	0%	-
Load resource data	207	100%		$ 268	0%	-
Season assessment	208	100%		$ 223	0%	-
Queue management	208	100%		$ 615	0%	-
Annual delivery assessment	210	100%		$ 25	0%	-
Total Long Term Transmission Planning process direct costs (activity 204 = $4,273 x factor of 50%)				**$ 9,993**		**$ 2,137**
From Page 1 - 2013 Revenue Requirement using 2013 ABC Data						
Total System Operations Costs before allocation of indirect costs						$ 48,915
Percentage of Long Term Transmission Planning process costs to ABC level 2 Direct Costs ($2,137 / $48,915)						4.37%
Total System Operations Indirect Dollars Allocated						$ 88,809
Long Term Transmission Planning process allocated indirect costs (4.37% x $88,809)						**$ 3,879**
Total Long Term Transmission Planning process costs ($2,137 + $3,879)						**$ 6,015**

Annual Planning Coordinator Service Charge Calculation

Total number of transmission circuits in ISO 2014/2015 Transmission Plan	1,550
Total number of transmission circuits in Southern California Edison Power system	4
Long Term Transmission Planning process cost per transmission circuit in ISO 2014/2015 Transmission Plan_SCE (in actual dollars)	$ 3,881
Annual Planning Coordinator service charge (in actual dollars)	**$ 15,524**