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August 11, 2006

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

Re: California Independent System Operator Corporation
Docket No. ER06-___-000
Transmission Control Agreement, Rate Schedule No. 7

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, the California Independent System Operator Corporation ("ISO"), on behalf of itself, Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("SCE"), the Cities of Anaheim, Azusa, Banning, and Riverside, California (collectively, "Southern Cities"), the City of Vernon, California ("Vernon"), Trans-Elect NTD Path 15, LLC ("Trans-Elect"), Western Area Power Administration – Sierra Nevada Region ("Western"), the City of Pasadena, California ("Pasadena"), and Trans Bay Cable LLC ("TBC"), respectfully submits for filing with the Federal Energy Regulatory Commission ("Commission" or "FERC") an amendment to the Transmission Control Agreement ("TCA") among the ISO and Participating Transmission Owners ("Participating TOs").[1] The current Participating TOs are PG&E, SDG&E, SCE, the Southern Cities, Vernon, Trans-Elect, Western, and Pasadena. Vernon became a New Participating TO as described in Section I.B, *infra*. The Southern Cities became New Participating TOs as described in Section I.C, *infra*. Trans-Elect became a New Participating TO as described in Section I.D, *infra*. Western is a partial Participating TO as described in *California*

[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, Appendix A to the ISO Tariff.

Independent System Operator Corporation, 109 FERC ¶ 61,153 (2004) ("Western Order"), and Section I.E, *infra*. Pasadena became a New Participating TO as described in Section I.F, *infra.*

The revisions being filed today are made in order to permit TBC to become a Participating TO, to identify the transmission interests (*i.e.*, the Entitlement) that TBC will be turning over to the ISO's Operational Control, and to make other modifications to the TCA that have been agreed upon by the parties to the TCA.

Two copies of the instant filing are provided to be date-stamped and returned to the messenger.

I. BACKGROUND

A. The Initial TCA Filings

The TCA is the agreement among the ISO and Participating TOs that establishes the terms and conditions under which Transmission Owners place certain transmission facilities and Entitlements under the ISO's Operational Control, thereby becoming Participating TOs. The TCA describes how the ISO and each Participating TO will discharge its respective duties and responsibilities with respect to the operation of those facilities and Entitlements. The initial TCA was filed as part of the comprehensive "Phase II" filings submitted by the trustee on behalf of the ISO on March 31, 1997. Refinements to the TCA were made as a result of an ongoing stakeholder process, and a revised TCA was submitted on August 15, 1997, in compliance with the Commission's order in *Pacific Gas and Electric Company, et al.*, 80 FERC ¶ 61,128. In its order dated October 30, 1997, the Commission granted interim and conditional authorization to the ISO to commence operations and required certain modifications to the TCA. *Pacific Gas and Electric Company, et al.*, 81 FERC ¶ 61,122. The ISO filed the revised TCA on February 20, 1998. By order dated March 30, 1998, *California Independent System Operator Corporation*, 82 FERC ¶ 61,325 ("March 30, 1998 Order"), the Commission conditionally accepted the TCA for filing to become effective on the ISO Operations Date and required further modifications to be made in a compliance filing within 60 days of the ISO Operations Date.[2]

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[2] March 30, 1998 Order, 82 FERC at 62,276-79. The ISO made the compliance filing on June 1, 1998. On February 11, 1999, as amended on April 19, 1999, the ISO filed a supplement to the TCA consisting of operating instructions and curtailment priorities for Path 15. The Commission accepted these submissions by order dated June 17, 1999 in Docket No. ER99-1770-000. *California Independent System Operator Corporation*, 87 FERC ¶ 61,312 ("June 17, 1999 Order"). On rehearing of the June 17, 1999 Order, the Commission granted in part and denied in part rehearing, and directed the ISO to make another compliance filing. *California*

B. The TCA Filings to Add Vernon as a New Participating TO

On December 21, 2000, the ISO filed with the Commission an amended version of the TCA intended to accommodate Vernon's application to become a New Participating TO. That amended TCA was executed by the ISO, the Original Participating TOs, and Vernon. By order dated February 21, 2001, *California Independent System Operator Corporation, et al.*, 94 FERC ¶ 61,141, the Commission accepted the amended TCA and granted waiver of the notice requirement so that the amended TCA was made effective as of January 1, 2001. The Commission ordered that the ISO make a compliance filing of the amended TCA, however, to conform with Commission Order No. 614. On March 23, 2001, the ISO made that compliance filing of the TCA, which the Commission accepted by letter order issued May 1, 2001.

C. The TCA Filings to Add the Southern Cities as New Participating TOs

On November 25, 2002, the ISO filed with the Commission an amended version of the TCA intended to accommodate the Southern Cities' applications to become New Participating TOs. That amended TCA was executed by the ISO, the Original Participating TOs, Vernon, and the Southern Cities. By order dated January 24, 2003, *California Independent System Operator Corporation*, 102 FERC ¶ 61,061 ("January 24, 2003 Order"), the Commission conditionally accepted the amended TCA and granted waiver of the notice requirement so that the amended TCA was made effective as of January 1, 2003. The Commission ordered that ISO make a compliance filing of the amended TCA, however, to, *inter alia*, remove language (included in TCA § 3.4) allowing Participating TOs to withdraw from the ISO when faced with an adverse tax action. The Southern Cities and the ISO requested rehearing on this element of the January 24, 2003 Order, requesting that the language of TCA § 3.4 remain unchanged. In its April 15, 2003 compliance filing, the ISO requested that the Commission not act on the removal of this language until it had ruled on the requests for rehearing. By order issued May 2, 2003, *California Independent System Operator Corporation*, 103 FERC ¶ 61,113 ("May 2, 2003 Order"), the Commission granted rehearing with regard to the withdrawal provisions, and allowed § 3.4 to remain in the TCA as proposed in the ISO's November 25, 2002 filing. In light of this directive, the ISO submitted a motion to withdraw elements of its April 15, 2003 compliance filing. By order issued November 17, 2003, *California Independent System Operator Corporation*, 105 FERC ¶ 61,207 ("November 17, 2003 Order"), the Commission conditionally accepted the April 15, 2003 compliance filing and granted the ISO's

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Independent System Operator Corporation, 99 FERC ¶ 61,212 (2002). The ISO submitted the compliance filing on June 21, 2002, and the Commission accepted it by letter order dated May 28, 2003.

motion to withdraw. On March 25, 2004, the ISO submitted a filing in compliance with the November 17, 2003 Order. By order issued March 22, 2005, *California Independent System Operator Corporation*, 110 FERC ¶ 61,297 ("March 22, 2005 Order"), the Commission accepted the March 25, 2004 compliance filing, subject to a revision to TCA § 3.4.8. On April 6, 2005, the ISO submitted a filing in compliance with the March 22, 2005 Order, which the Commission accepted by letter order issued July 18, 2005.

D. The TCA Filing to Add Trans-Elect as a New Participating TO

Trans-Elect filed with the ISO a notice of intent in January 2003, and a subsequent application that proposed turning over Operational Control of its Entitlements in the proposed Path 15 upgrade project to the ISO, stating its intent to become a Participating TO on or after January 1, 2004, when the Path 15 transmission facilities in which it has transmission Entitlements were energized. On August 15, 2003, the ISO filed with the Commission, in Docket No. ER03-1217-000, the revisions to the TCA necessary to permit Trans-Elect to join the ISO as described above. By letter order issued October 14, 2003, the Commission accepted these revisions to the TCA, to become effective upon notice after January 1, 2004. The Path 15 transmission facilities were accepted for exercise of Operational Control by the ISO on December 22, 2004, and the ISO filed a notice with the Commission on that date advising of the ISO's acceptance of those facilities and the associated effective date of the TCA tariff sheets previously accepted by the Commission contingent on the ISO's issuance of that notice. The tariff sheets made effective as of December 22, 2004, include the tariff sheets making Trans-Elect a New Participating TO.

E. The TCA Filing to Add Western as a Partial Participating TO

Western filed with the ISO a notice of intent in December 2003, and a subsequent application that proposed turning over Operational Control of only its rights and Entitlements in the proposed Path 15 upgrade project to the ISO, stating its intent to become a "partial" Participating TO when the Path 15 transmission facilities in which it has transmission rights and Entitlements commenced commercial operation. On September 7, 2004, the ISO filed with the Commission an amended version of the TCA and Amendment No. 63 to the ISO Tariff ("Amendment No. 63") to accommodate Western's becoming a partial Participating TO with regard to Western's interest in the Path 15 upgrade. By order issued November 5, 2004, *California Independent System Operator Corporation*, 109 FERC ¶ 61,153 ("Western Order"), the Commission accepted the proposed revisions to the TCA, subject to modifications, effective November 1, 2004; the Commission also conditionally accepted Amendment No. 63, subject to further Commission action and refund, and established dispute resolution service procedures. On December 6, 2004, the ISO submitted further modifications to the TCA to comply with the Western Order. Also on that date, Western and SCE submitted requests for rehearing and clarification of the Western Order. By letter order issued April 13, 2005, the Commission accepted the ISO's December 6, 2004 compliance filing. By order issued May 16, 2006, *California Independent System Operator Corporation*, 115 FERC ¶ 61,178 ("May 16, 2005 Order"), the Commission granted Western's request for rehearing and clarification and denied SCE's request for rehearing and clarification.

F. The TCA Filing to Add Pasadena as a New Participating TO

Pasadena filed with the ISO a notice of intent in June 2004, and a subsequent application that proposed turning over Operational Control of its facilities and Entitlements to the ISO, stating its intent to become a Participating TO effective January 1, 2005. On December 23, 2004, the ISO filed with the Commission, in Docket No. ER05-381-000, the revisions to the TCA necessary to permit Pasadena to join the ISO as described above.

On October 29, 2004, in Docket No. EL05-18-000, Pasadena submitted a petition requesting that the Commission issue an order, *inter alia*, accepting Pasadena's Transmission Revenue Requirement and Transmission Owner Tariff effective as of the later of January 1, 2005 or the effective date of a TCA acceptable to Pasadena.

By order issued February 11, 2005, *California Independent System Operator Corporation*, the Commission accepted for filing the revisions to the TCA contained in the ISO's December 23, 2004 filing and suspended them for a nominal period, effective January 1, 2005, subject to refund. The Commission also initiated a hearing concerning the justness and reasonableness of the revisions to the TCA and ordered hearing procedures to be held in abeyance to provide time for settlement judge procedures. Further, the Commission consolidated Docket Nos. ER05-381-000 and EL05-18-000 for purposes of settlement, hearing, and decision. Following settlement judge procedures, on May 27, 2005, Pasadena filed a settlement agreement to resolve all issues set for hearing in those consolidated dockets. By order issued June 15, 2005, *City of Pasadena, California and California Independent System Operator Corporation*, 111 FERC ¶ 63,065, the Presiding Administrative Law Judge in the proceeding certified the settlement agreement to the Commission as uncontested. By order issued July 26, 2005, *City of Pasadena, California and California Independent System Operator Corporation*, 112 FERC ¶ 61,126, the Commission approved the uncontested settlement.

G. The Trans Bay Cable Project and the TCA Filing to Add TBC as a New Participating TO

On May 19, 2005, TBC filed with the Commission an operating memorandum among TBC, the City of Pittsburg, California ("City of Pittsburg"), and Pittsburg Power Company ("Pittsburg Power") that set forth the rate principles and operational responsibilities pursuant to which TBC would pursue the development, financing, construction, and operation of a new, single, high-voltage direct current transmission line that would be used to transmit electricity from an existing PG&E substation adjacent to the City of Pittsburg, underneath San Francisco Bay, to an existing PG&E substation within the City of San Francisco (the "Trans Bay Cable Project" or "Project"). By order dated July 22, 2005, *Trans Bay Cable LLC*, 112 FERC ¶ 61,095 ("July 22, 2005 Order"), the Commission accepted for filing the operating memorandum filed by TBC and the rate principles contained therein. By order issued January 18, 2006, *Trans Bay Cable LLC*, 114 FERC ¶ 61,031, the Commission granted clarification of the July 22, 2005 Order.

TBC will own an Entitlement to the entire capacity of the Project facilities, which is estimated to be 400 MW. It is anticipated that Pittsburg Power will hold the underlying ownership interest in the Project facilities. The line is expected to be energized in early 2009.

On September 8, 2005, the ISO Governing Board unanimously approved the Project as the preferred long-term transmission alternative to address reliability concerns regarding the San Francisco peninsula area. Under the procedures outlined in Section 4.3.1 of the ISO Tariff, TBC filed with the ISO a notice of intent on December 30, 2005, and an application (which included a draft TO Tariff) on January 13, 2006, to become a New Participating TO effective on the commercial operation date of the Project. TBC has proposed to turn over Operational Control of its Entitlement to the Project to the ISO.

TBC's application, including its draft TO Tariff, was posted on the ISO Home Page on January 13, 2006, for Market Participant review, and comments were received from PG&E, SCE, and SDG&E. The ISO responded to each of the comments and apprised TBC of the comments and the ISO's response.

On June 14, 2006, after the issues raised by the parties had been resolved through negotiations (see Section II.A.2 below), the ISO Governing Board unanimously voted to accept TBC's application for Participating TO status, conditioned on TBC obtaining approval of its TO Tariff and Transmission Revenue Requirement by the Commission. Pursuant to that action by the ISO Governing Board, the ISO has included in this filing a set of amendments to add TBC as a conditional party to the TCA, similar to the approach and timing of prior

TCA amendments to add Trans-Elect as a New Participating TO and Western as a partial Participating TO.[3]

Pasadena and the Cities of Anaheim and Riverside have indicated that, although they do not object to TBC becoming a New Participating TO (or to any of the other amendments proposed to the TCA), the approval process for amendments to an agreement such as the TCA is time-consuming for governmental entities such as themselves, and they could not execute the amendments to the TCA in time for this filing to be made. The executed signature pages for those Participating TOs that have been unable to complete their approval processes as of the date of this filing will be filed when such approvals have been obtained. The ISO anticipates that these approval processes will be completed, and the executed signature pages provided, well in advance of the time when the TCA becomes effective as described in Section III, below.

In addition to the TCA amendments to add TBC as a New Participating TO filed herewith, the TCA parties determined in the course of their negotiations that the provisions of the ISO Tariff regarding recovery by a Participating TO of its Low Voltage Transmission Revenue Requirement ("LVTRR") do not address sufficiently clearly the circumstances of TBC as a "merchant" Participating TO that does not serve any Load in the ISO Control Area. On August 3, 2006, the ISO Governing Board voted to authorize the ISO to file a proposed amendment to the ISO Tariff with the Commission to address the circumstances of TBC and any similarly-situated "merchant" Participating TO in the future. The ISO anticipates that this ISO Tariff amendment will be filed with the Commission soon after this filing.

Prior to completion of construction of the Project transmission facilities, TBC will file a Transmission Revenue Requirement for approval by the Commission. Contemporaneously, TBC also will file a Transmission Owner ("TO") Tariff for approval by the Commission, including a Transmission Revenue Balancing Account. Once TBC has made this filing, the ISO anticipates making an informational filing to revise its transmission Access Charge rates to account for the addition of TBC as a New Participating TO. Also, as it did for the addition of Trans-Elect as a New Participating TO and Western as a partial Participating TO, once the commercial operation date for the Trans Bay Cable Project is finalized, the ISO will make an informational filing identifying that date as the effective date of TBC's status as a New Participating TO and party to the TCA.

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[3] As discussed further below, the timing of this filing has been dictated by the need for Commission action prior to the closing of the financing for the construction of the Trans Bay Cable Project. For this reason, it was not possible to wait until the necessary approval processes of all the Participating TOs had taken place before making this filing.

H. Background Regarding Revisions to the TCA Other than Those Concerning TBC

In addition to the TCA amendments to add TBC as a New Participating TO, the parties to the TCA have identified various other provisions of the TCA that need to be updated. In an attempt to minimize the number of filings of TCA amendments, the parties have combined the amendments to add TBC as a New Participating TO with these additional amendments. These additional amendments are described in more detail in Section II.B of this letter.

II. REVISIONS TO THE TCA

A. Changes Relating to TBC's Becoming a Participating TO

1. Changes to Table of Contents

The Table of Contents for the TCA has been modified to reflect the addition of TBC as a Participating TO.

2. Addition of Provisions to Section 4

Section 4.4.4 has been added to the TCA to address TBC's transfer of Operational Control of TBC's Entitlement to the Project to the ISO. In response to TBC's submittal of its application for status as a Participating TO and in view of its operating memorandum with the City of Pittsburg and Pittsburg Power as the owner of the Project transmission facilities, the ISO received comments from PG&E, SCE, and SDG&E particularly focused on the possibility of TBC withdrawing as a Participating TO in the future after recovering all or part of its investment and then obtaining further revenue recovery pursuant to another mechanism, particularly by transferring its Entitlement to a non-FERC jurisdictional entity that would obtain further revenue recovery inconsistent with FERC ratemaking principles. In response to these comments, TBC engaged in extensive negotiations with the ISO and other TCA parties to develop the additional provisions proposed to be added as new Section 4.4.4 of the TCA to provide assurances that this will not be the case.

Section 4.4.4.1 acknowledges the Commission's jurisdiction over the rates for the Project, including the rate principles previously approved by the Commission for the Project. Section 4.4.4.2 limits TBC's ability to withdraw from the TCA to those circumstances specified in the TCA. Section 4.4.4.3 sets forth the primary provision addressing the comments described above by specifying conditions on TBC's ability to transfer its Entitlements, which conditions include requirements that the transferee assume TBC's rights and obligations under the

TCA and that it become a Participating TO itself. Section 4.4.4.4 recognizes that the operating memorandum among TBC, the City of Pittsburg, and Pittsburg Power does not pertain to the potential transfer of TBC's Entitlements. Section 4.4.4.5 preserves the rights of parties to take positions before the Commission on the proposed TRR of TBC or any successor. Section 4.4.4.6 provides protection for TBC in specifying that the provisions of Section 4.4.4 will cease to apply to TBC if TBC receives less revenue than is due to it pursuant to the ISO Tariff in specified amounts and for specified periods of time, which amounts and periods of time were the subject of substantial negotiation among the parties. Section 4.4.4.7 preserves the applicability of the other provisions of the TCA if Section 4.4.4 ceases to apply to TBC.

3. Addition of New Section 39

A signature page for TBC has been provided in new Section 39 of the TCA.

4. Addition of New Appendix A

A new Appendix A has been added to the TCA to identify the Entitlement that TBC proposes to transfer to the ISO's Operational Control. As described in Section I.G above, this Entitlement includes the entire capacity of the Project facilities, which is estimated to be 400 MW.

5. Changes to Appendix F

Appendix F to the TCA has been expanded to identify the persons to contact at TBC for notice purposes.

B. Other Revisions to the TCA

1. Changes to Table of Contents

The Table of Contents for the TCA has been modified to correct several minor errors and omissions.

2. Deletion of Section 8.3

Section 8.3 of the TCA has been deleted to reflect the agreement of the parties that other provisions of the TCA, including Sections 4.2, 8.1, and 8.2, and the ISO Tariff already impose appropriate obligations on the Participating TOs regarding the subject of Section 8.3 – the operation of Critical Protective Systems, including Remedial Action Schemes, that are not part of the ISO Controlled Grid. Based on this understanding, the parties have agreed that the provisions of Section 8.3 should be removed to eliminate redundancy and the possibility of conflict with other applicable provisions.

3. Restoration of Section 10.5

In the May 16, 2006 Order, the Commission granted Western's request for rehearing and clarification. The Commission stated that its rejection in the Western Order of proposed Section 10.5 of the TCA concerning Western's general requirements for interconnection was without prejudice. May 16, 2006 Order at PP 21-24. Pursuant to the Commission's directives, the provision the Commission ordered restored to the TCA concerning Western's general requirements for interconnection has been included in Section 10.5 of the TCA.

4. Changes to Provisions in Section 14

Provisions in Section 14 of the TCA have been modified to be consistent with the comprehensive revisions to the ISO Transmission Maintenance Standards applicable to the Participating TOs set forth in TCA Appendix C.[4] The revisions to Appendix C and Section 14 have been approved by the ISO's Transmission Maintenance Coordination Committee ("TMCC") and agreed to by the parties to the TCA. Section 14.1 has been revised to reflect that the standards previously identified as to be adopted by the ISO now have been adopted and are set forth in the newly revised version of Appendix C. Section 14.2 of the TCA has been deleted as out-of-date given its reference to pre-existing standards that will no longer be applicable given the new standards now incorporated into Appendix C. Pursuant to the deletion of Section 14.2, the provisions in Sections 14.3, 14.4, and 14.5 of the TCA have been re-numbered. Provisions in revised Sections 14.2, 14.3, and 14.4 (formerly Sections 14.3, 14.4, and 14.5) of the TCA have been modified to make their references consistent with the provisions of revised Appendix C.

5. Changes to Provisions in Section 17

Provisions in Sections 17.2 and 17.5 of the TCA have been modified to make them consistent with the revised provisions regarding Participating TO recordkeeping and reporting to the ISO incorporated into the comprehensive revision of the ISO Transmission Maintenance Standards for Participating TOs set forth in revised Appendix C. Section 17.2.1 has been revised to make clear that reports and other matters regarding ISO Transmission Maintenance Standards are now set forth in Appendix C. Section 17.2.2 has been revised to make clear that the ISO retains discretion regarding its need for information

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[4] Unless otherwise defined herein, the term "ISO Transmission Maintenance Standards" and other capitalized terms in Sections II.B.4, II.B.5, and II.B.9 of the instant filing have the meanings set forth in Section 1 ("Definitions") of TCA Appendix C.

about the physical and electrical properties of Participating TO Transmission Facilities. Section 17.2.3 has been revised to delete the reference to Participating TO reports to the ISO about compliance with ISO Transmission Maintenance Standards, as this matter is now covered by Appendix C. Sections 17.2.4 and 17.5 have been revised to clarify that their provisions regarding reporting requirements are subject to the other provisions of the TCA, including specification of Transmission Facility Maintenance reporting requirements in Appendix C.

6. Changes to Sections 27 Through 37, and Addition of New Section 38

Sections 27 through 37 of the TCA have been modified, and a duplicate Section 37 has been changed to Section 38, to reflect the execution by the parties to the TCA of the current version of the TCA provided in the instant filing and to correct a typographical error.

7. Changes to Provisions in Appendix A

Provisions in Appendix A to the TCA have been modified to update the listings of agreements that establish the Entitlements that have been turned over to ISO Operational Control. These modifications reflect the termination or amendment of certain of those agreements, or in some cases provide clarifications to the descriptions of those agreements, for PG&E, SCE, SDG&E, and the City of Riverside. SCE has also added a listing of an agreement that had been inadvertently omitted from the prior listing. In addition, a listing of the Owners Coordinated Operations Agreement ("OCOA") has been added to the listing of agreements for PG&E, SCE, and SDG&E to recognize that the OCOA was entered into as of January 1, 2005 to replace the Coordinated Operations Agreement governing the coordinated operation of the Pacific AC Intertie lines with the California-Oregon Transmission Project, which terminated as of that date.

8. Changes to Provisions in Appendix B

Provisions in Appendix B to the TCA have been modified to update the listings of agreements that establish Encumbrances on the ISO Controlled Grid. These modifications reflect the termination or amendment of certain of those agreements, or in some cases provide clarifications to the descriptions of those agreements, for PG&E, SCE, and SDG&E.

9. Changes to Provisions in Appendix C

Appendix C to the TCA has been modified to implement comprehensive revisions to the provisions of the ISO Transmission Maintenance Standards applicable to the Participating TOs. These revisions have been approved by the TMCC and agreed by the parties to the TCA. The TMCC is established pursuant to Section 7 of Appendix C and is composed of representatives of Participating TOs and other stakeholders with an interest in the Transmission Facilities comprising the ISO Controlled Grid. The purpose of the TMCC is to help the ISO develop, review, and revise ISO Transmission Maintenance Standards and perform the following duties: periodically convey information to the ISO Governing Board, seek input from Participating TOs and interested stakeholders regarding ISO Transmission Maintenance Standards, and make recommendations with respect to proposed amendments and revisions to the ISO Transmission Maintenance Standards. The TMCC initiated the process of revising the ISO Transmission Maintenance Standards in Appendix C in 2003, and discussions among the TMCC members and negotiations among the TCA parties have recently concluded with agreement to the revisions to Appendix C (and associated revisions to TCA Sections 8, 14, and 17).

The TMCC recommended that an effort to review Appendix C was needed to bring it up to date with five years of Maintenance program experience and progress. The review and proposed amendments have eliminated duplication of terms and conditions that will reduce the potential for future inconsistencies in language with other documents, including other TCA sections, other Appendix C sections, and ISO Maintenance Procedures. The TMCC did not recommend any changes to the fundamental components of the ISO Transmission Maintenance Standards in TCA Appendix C. TMCC members indicated that fundamental components of the ISO Transmission Maintenance Standards were serving their purpose as intended and that they did not need to be functionally changed. As such, all fundamental components of the ISO Transmission Maintenance Standards are proposed to remain in place, including Availability Measures, the PTO Maintenance Practices, standardized Maintenance reports, and Maintenance reviews.

The specific revisions to Appendix C include the following. A table of contents has been added. The definitions in Section 1 have been revised to better reflect the intent and usage of the defined terms and new defined terms have been added to reflect the existence of the Maintenance Procedures. In particular, the definitions of the terms "Availability Measures," "Forced Outage," "Maintenance Practices," and "Maintenance Procedures" have been revised to reflect refinements in the ISO's overall Maintenance program and to make them consistent with the revisions to and more detailed specifics of the program. Consistency in the use of defined terms has also been improved throughout

Appendix C, and references to the Maintenance Procedures have been added where appropriate.

Section 2 has been reorganized to better align key concepts with section titles and the language has been updated to reflect the years of Maintenance program experience and progress since Appendix C was originally drafted.

In Section 2.2 and Section 4 the concepts associated with the Availability Measures have been refined, but the essential elements of the Availability Measures have not been modified.

In Sections 2.3, 2.4, 4.3, and 6, the specification of Participating TO recordkeeping and reporting requirements has been revised to better support the ISO Maintenance review process.

Section 2.5 has been deleted and combined with a revised Section 9 to consolidate terms and conditions concerning incentives and penalties and to eliminate a potential conflict between the different provisions of the two sections.

In Section 5, the description of appropriate Maintenance Practices has been refined and more detail has been added particularly regarding the procedures associated with ISO recommendations for revisions to a Participating TO's Maintenance Practices, based on the years of experience with the ISO's Maintenance program.

Sections 7 and 8 have been revised to add more specificity and clarity particularly regarding the responsibilities and authority of the TMCC. The language of Sections 3, 10, and 11 has been revised to make it more clear and specific. In addition, duplication among provisions of Appendix C and between Appendix C and provisions of the body of the TCA has been eliminated where appropriate.

10. Changes to Provisions in Appendix E

Provisions in Appendix E to the TCA have been modified to reflect revisions to the standards and requirements applicable to SCE's operation of the San Onofre Nuclear Generating Station.

III. EFFECTIVE DATE

Pursuant to Section 35.3 of the Commission's regulations, 18 C.F.R. § 35.3, the ISO requests that all of the changes to the TCA proposed in the instant filing be made effective on October 10, 2006 (*i.e.*, sixty days after submittal of the filing), with the exception of TBC's signature page (Original Sheet No. 72D), Appendix A (Original Sheet No. 103D), and Appendix F (Original Sheet No. 238). Pursuant to Section 35.11 of the Commission's regulations, 18 C.F.R. § 35.11, the ISO respectfully requests waiver of the notice requirements of Section 35.3 to permit the proposed changes related to TBC's signature page and Appendices A and F of the TCA to become effective upon notice after October 10, 2006, and submits that good cause exists for granting the requested waiver. TBC has advised the ISO that, as was the case for Trans-Elect, it expects that its lenders will impose a condition precedent to closing of the financing for construction of the Project, which in effect will require approval by the Commission of the TCA amendments to add TBC as a New Participating TO. The ISO, therefore, respectfully requests waiver of the 120-day advance filing limitation imposed by Section 35.3 so that the closing of the financing for construction of the Project may proceed on schedule.

The ISO proposes to issue notice of the actual effective date of the revised TCA, including TBC's signature page and Appendices A and F, when (1) the ISO accepts Operational Control of the TBC Entitlement shown in the TBC Appendix A and (2) TBC files its TO Tariff and Transmission Revenue Requirement with the Commission, with the effective date being conditional on Commission approval of TBC's TO Tariff and Transmission Revenue Requirement. Granting the requested waiver, therefore, is appropriate. The ISO's proposal for establishing the commercial operation date of the Trans Bay Cable Project as the official effective date for TBC as a party to the TCA is described further in Section I.G above.

IV. EXPENSES

No expense or cost associated with this filing has been alleged or judged in any judicial or administrative proceeding to be illegal, duplicative, unnecessary, or demonstratively the product of discriminatory employment practices.

V. COMMUNICATIONS

The ISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

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

VI. SERVICE

Copies of this transmittal letter and all attachments have been served upon the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, PG&E, SDG&E, SCE, the Southern Cities, Vernon, Trans-Elect, Western, Pasadena, TBC, and all parties with effective Scheduling Coordinator Agreements under the ISO Tariff.

VII. SUPPORTING DOCUMENTS

In addition to this transmittal letter, the instant filing contains the following attachments:

Attachment A — Revised pages of the Transmission Control Agreement, provided in a format that complies with Order No. 614, *Designation of Electric Rate Schedule Sheets*, FERC Stats. & Regs., Regs. Preambles ¶ 31,096 (2000); and

Attachment B — Black-lined text showing the changes to the Transmission Control Agreement.

Please contact the undersigned with any questions.

Respectfully submitted,

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ATTACHMENT A

4.4.4 Trans Bay Cable

4.4.4.1 In addition to the foregoing, the ISO, Trans Bay Cable LLC ("Trans Bay Cable"), and the Participating TOs acknowledge and agree that, following the ISO's approval of Trans Bay Cable's application for Participating TO status and upon the effective date of Trans Bay Cable's TO Tariff as approved by FERC, Trans Bay Cable shall be entitled and obligated to recover the just and reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has Entitlements through Trans Bay Cable's Transmission Revenue Requirement as established from time to time by FERC, including the specific rate principles approved by FERC in Docket No. ER05-985, to the extent that the transmission assets and associated facilities used to provide the Entitlements, as well as the Entitlements themselves, are placed under ISO Operational Control.

4.4.4.2 In reliance on the continued availability of a FERC-approved Transmission Revenue Requirement, as set forth above, Trans Bay Cable will not withdraw from this Agreement except in connection with the transfer, sale or disposition of any of its Entitlements in compliance with Sections 3.3, 4.4, and any other applicable provision of this Agreement.

4.4.4.3 If Trans Bay Cable should seek to transfer, sell or dispose of its Entitlements or any part thereof, then in addition to any and all other obligations imposed on such a transfer, sale or disposition by this Agreement, any applicable provisions of the ISO Tariff, and FERC rules and regulations, Trans Bay Cable shall require as a condition of such transfer, sale or disposition that the transferee of any of its Entitlement(s): (a) assume in writing Trans Bay Cable's rights and obligations under this Agreement, including without limitation all of the obligations imposed by this Section 4.4.4, *e.g.*, the obligation to recover the just and reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has Entitlements, as set forth in Section 4.4.4.1, exclusively through a FERC-approved Transmission Revenue Requirement; (b) become a Participating TO in the ISO; and (c) assume the obligation to bind each and every one of its transferees, successors and assigns to all of the obligations assumed by Trans Bay Cable under this Agreement. For the avoidance of doubt, the transfer of any of Trans Bay Cable's Entitlements cannot take place unless and until the holder of any such Entitlements has, in conjunction with the transfer, become a Participating TO in the ISO.

4.4.4.4 For the avoidance of doubt, the Parties hereby also confirm that the Operating Memorandum dated May 16, 2005, between Trans Bay Cable, the City of Pittsburg, California, and Pittsburg Power Company and filed by Trans Bay Cable in Docket No. ER05-985, including the option agreement contained therein, does not address or pertain to any transfer, disposition, sale or purchase of any of Trans Bay Cable's Entitlements.

4.4.4.5 Nothing in this Section 4.4.4 shall be interpreted as affecting the right of any party to seek to increase or decrease, at the FERC or appeals therefrom, the established or proposed Transmission Revenue Requirement of Trans Bay Cable or any subsequent holder of any of the Entitlements.

4.4.4.6 Notwithstanding the foregoing subsections of Section 4.4.4, this Section 4.4.4 shall become null and void in the event of and upon the first to occur of: (a) Trans Bay Cable receives for three (3) consecutive months either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff, or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff, with each such underpayment or pro rata reduction equal to or greater than twenty percent (20%) of the monthly amount due and owing to Trans Bay Cable from the ISO, or (b) Trans Bay Cable receives either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff which, when calculated on a cumulative annual basis, is equal to or greater than five percent (5%) of the total amount due and owing to Trans Bay Cable from the ISO for the twelve (12) month period ending prior to the month or months in which such underpayment or pro rata reduction occurs, *provided* such an underpayment or pro rata reduction does not result from: (i) Access Charge sales fluctuations that impact the monthly Access Charge revenue disbursement to Trans Bay Cable, but which are subject to annual TRBAA true-ups to be made by the Participating TO pursuant to Section 6.1 of Schedule 3 of Appendix F of the ISO Tariff; (ii) Trans Bay Cable's action or failure to act; (iii) an error that has been corrected by the ISO; or (iv) a billing or payment dispute between Trans Bay Cable and the ISO.

4.4.4.7 Should this Section 4.4.4 become null and void under Section 4.4.4.6, then Trans Bay Cable, the ISO and the other Participating TOs shall remain bound by all of the remaining provisions of this Agreement.

9. SYSTEM EMERGENCIES

9.1. ISO Management of Emergencies.

The ISO shall manage a System Emergency pursuant to the provisions of Section 2.3.2 of the ISO Tariff. The ISO may carry out unannounced tests of System Emergency procedures pursuant to the ISO Tariff.

9.2. Management of Emergencies by Participating TOs.

9.2.1 **ISO Orders**. In the event of a System Emergency, the Participating TOs shall comply with all directions from the ISO regarding the management and alleviation of the System Emergency unless such compliance would impair the health or safety of personnel or the general public.

9.2.2 **Communication**. During a System Emergency, the ISO and Participating TOs shall communicate through their respective control centers, in

10.5 Interconnection Responsibilities of Western.

Notwithstanding any other provision of this Section 10, the responsibilities of Western to allow interconnection to its Path 15 Upgrade facilities and Entitlements set forth in Appendix A (Western) shall be as set forth in Western's General Requirements for Interconnection as those requirements are set forth in Western's TO Tariff or in Western's "Open Access Transmission Tariff" ("OATT"), as applicable. Western shall be subject to the provisions of this Section 10 to the extent they are not inconsistent with the provisions of Western's TO Tariff or OATT, as applicable. Execution of this Agreement shall not constitute agreement of any Party that Western is in compliance with FERC's regulations governing interconnections.

11. EXPANSION OF TRANSMISSION FACILITIES

The provisions of Section 3.2 of the ISO Tariff will apply to any expansion or reinforcement of the ISO Controlled Grid affecting the transmission facilities of the Participating TOs placed under the Operational Control of the ISO.

12. USE AND ADMINISTRATION OF THE ISO CONTROLLED GRID

12.1. Use of the ISO Controlled Grid.

Except as provided in Section 13, use of the ISO Controlled Grid by the

14. MAINTENANCE STANDARDS

14.1. ISO Determination of Standards.

The ISO has adopted and shall maintain, in consultation with the Participating TOs through the Transmission Maintenance Coordination Committee, and in accordance with the requirements of this Agreement, the standards for the maintenance, inspection, repair, and replacement of transmission facilities under its Operational Control in accordance with Appendix C. These standards, as set forth in Appendix C, are and shall be performance-based or prescriptive or both, and provide for high quality, safe, and reliable service and shall take into account costs, local geography and weather, the Applicable Reliability Criteria, national electric industry practice, sound engineering judgment and experience.

14.2. Availability.

14.2.1 **Availability Measure**. The ISO performance-based standards shall be based on the availability measures described in Appendix C of this Agreement.

14.2.2 **Excluded Events**. Scheduled Approved Maintenance Outages and certain Forced Outages will be excluded pursuant to Appendix C of this Agreement from the calculation of the availability measure.

14.2.3 **Availability Measure Target**. The ISO and each Participating TO shall jointly develop for the Participating TOs an availability measure target, which may be defined by a range. The target will be based on prior Participating TO performance and developed in accordance with Appendix C of this Agreement.

14.2.4 **Calculation of Availability Measure**. The availability measure shall be calculated annually by the Participating TO and reported to the ISO for evaluation of the Participating TO's compliance with the availability measure target. This calculation will be determined in accordance with Appendix C of this Agreement.

14.2.5 **Compliance with Availability Measure Target**. The ISO and the Participating TO may track the availability measure on a more frequent basis (e.g., quarterly, monthly), but the annual calculation shall be the sole basis for determining the Participating TO's compliance with its availability measure target.

14.2.6 **Public Record**. The Participating TO's annual availability measure calculation with its summary data shall be made available to the public.

14.3. Revisions.

The ISO and Participating TOs shall periodically review Appendix C, through the Transmission Maintenance Coordination Committee process, and in accordance with the provisions of Appendix C and this Agreement shall modify Appendix C as necessary.

14.4. Incentives and Penalties.

The ISO may, subject to regulatory approval, and as set forth in Appendix C, develop programs which reward or impose sanctions on Participating TOs by reference to their availability measure and the extent to which the availability performance imposes demonstrable costs or results in demonstrable benefits to Market Participants.

15. DISPUTE RESOLUTION

In the event any dispute regarding the terms and conditions of this Agreement is not settled, the Parties shall follow the ISO ADR Procedure set forth in Section 13 of the ISO Tariff. The specific references in this Agreement to alternative dispute resolution procedures shall not be interpreted to limit the Parties' rights and obligations to invoke dispute resolution procedures pursuant to this Section 15.

16. BILLING AND PAYMENT

16.1 Application of ISO Tariff

The ISO and Participating TOs shall comply with the billing and payment provisions set forth in Section 11 of the ISO Tariff.

16.2 Refund Obligation

Each Participating TO, whether or not it is subject to the rate jurisdiction of the FERC under Section 205 and Section 206 of the Federal Power Act, shall make all refunds, adjustments to its Transmission Revenue Requirement, and adjustments to its TO Tariff and do all other things required of a Participating TO to implement any FERC order related to the ISO Tariff, including any FERC order that requires the ISO to make payment adjustments or pay refunds to, or receive prior period overpayments from, any Participating TO. All such refunds and adjustments shall be made, and all other actions taken, in accordance with the ISO Tariff, unless the applicable FERC order requires otherwise.

17. RECORDS AND INFORMATION SHARING

17.1. Records Relevant to Operation of ISO Controlled Grid.

The ISO shall keep such records as may be necessary for the efficient operation of the ISO Controlled Grid and shall make appropriate records available to a Participating TO, upon request. The ISO shall maintain for not less than five (5) years: (1) a record of its operating orders and (2) a record of the contents of, and changes to, the ISO Register.

17.2. Participating TO Records and Information Sharing.

17.2.1 **Existing Maintenance Standards**. Each Participating TO shall provide to the ISO, as set forth in Appendix C hereto: (1) the Participating TO's standards for inspection, maintenance, repair, and replacement of its facilities under the ISO's Operational Control; and (2) information, notices, or reports regarding the Participating TO's compliance with the inspection, maintenance, repair, and replacement standards set forth in Appendix C hereto.

17.2.2 **Other Records**. Each Participating TO shall provide to the ISO and maintain current data, records, and drawings describing the physical and electrical properties of the facilities under the ISO's Operational Control, which records shall be shared with the ISO under reasonable guidelines and procedures to be specified by the ISO.

17.2.3 **Required Reports**. Pursuant to this Agreement and the provisions of the ISO Tariff, each Participating TO shall provide to the ISO timely information, notices, or reports regarding matters of mutual concern, including:

i. System Emergencies, Forced Outages and other incidents affecting the ISO Controlled Grid;

ii. Maintenance Outage requests, including yearly forecasts required by Section 2.3.3.5 of the ISO Tariff; and

iii. System Planning Studies, including studies prepared in connection with Interconnections or any transmission facility enhancement or expansion.

17.2.4 **Other Reports**. The ISO may, in accordance with the provisions of this Agreement and Appendices hereto, upon reasonable notice to the Participating TO, request that the Participating TO provide the ISO with such information or reports as are necessary for the operation of the ISO Controlled Grid. The Participating TO shall make all such information or reports available to the ISO in the manner and time prescribed by this Agreement or Appendices hereto or, if no specific requirements are so prescribed, within a reasonable time and in a form to be specified by the ISO.

17.2.5 **Other Market Participant Information**. At the request of the ISO, a Participating TO shall provide the ISO with non-confidential information obtained by the Participating TO from other Market Participants pursuant to contracts between the Participating TO and such other Market Participants. Such requests shall be limited to information that is reasonably necessary for the operation of the ISO Controlled Grid.

notify all other Parties if it becomes aware that a significant incident affecting the ISO Controlled Grid has occurred. Subsequent to notification, each Party shall make available to the ISO all relevant data related to the occurrence of the significant incident. Such data shall be sufficient to accommodate any reporting or analysis necessary for the Parties to meet their obligations under this Agreement.

17.5. Review of Information and Record-Related Policies.

The ISO shall periodically review the requirements of this Section 17 and shall, consistent with reliability and regulatory needs, other provisions of this Agreement, and Appendices hereto, seek to standardize reasonable record keeping, reporting, and information sharing requirements.

18. GRANTING RIGHTS-OF-ACCESS TO FACILITIES

18.1. Equipment Installation.

In order to meet its obligations under this Agreement, a Party that owns, rents, or leases equipment (the equipment owner) may require installation of such equipment on property owned by another Party (the property owner), provided that the property is being used for an electric utility purpose and that the property owner shall not be required to do so if it would thereby be prevented from performing its own obligations or exercising its rights under this Agreement.

18.1.1 **Free Access**. The property owner shall grant to the equipment owner free of charge reasonable installation rights and rights of access to accommodate equipment inspection, repair, upgrading, or removal for the purposes of this Agreement, subject to the property owner's reasonable safety, operational, and future expansion needs.

27. SIGNATURE PAGE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

California Independent System Operator Corporation has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 8th day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendices A

Appendices B

Appendix C

Appendix D

Appendices E

Appendix F

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
151 Blue Ravine Road
Folsom, California 95630

by:____________________

Jim Detmers
Vice President, Operations

28. SIGNATURE PAGE

PACIFIC GAS AND ELECTRIC COMPANY

Pacific Gas and Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 7th day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (PG&E)

Appendix B (PG&E)

Appendix C

Appendix D

Appendix E (Diablo Canyon)

Appendix F

PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street
San Francisco, California 94105

by: ______________________

Stewart M. Ramsay
Vice President, Asset Management & Electric Transmission

29. SIGNATURE PAGE

SAN DIEGO GAS & ELECTRIC COMPANY

San Diego Gas & Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 8th day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (SDG&E)

Appendix B (SDG&E)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court
San Diego, California 92123

by: ______________________

James Avery
Senior Vice President of San Diego Gas & Electric

30. SIGNATURE PAGE

SOUTHERN CALIFORNIA EDISON COMPANY

Southern California Edison Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 24th day of July, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Edison)

Appendix B (Edison)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

by: ______________________

Ronald L. Litzinger
Senior Vice President, Transmission & Distribution

31. SIGNATURE PAGE

CITY OF VERNON

CITY OF VERNON has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 8th day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Vernon)

Appendix B (Vernon)

Appendix C

Appendix D

Appendix E

Appendix F

CITY OF VERNON

By: Leonis C. Malburg
LEONIS C. MALBURG, Mayor

ATTEST:

BRUCE V. MALKENHORST, JR.
Acting City Clerk

APPROVED AS TO FORM:

Jeff Harrison, Chief Assistant City Attorney

32. SIGNATURE PAGE

CITY OF ANAHEIM

CITY OF ANAHEIM has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ____ day of _____________, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Anaheim)

Appendix B (Anaheim)

Appendix C

Appendix D

Appendix F

CITY OF ANAHEIM

By:______________________________
Marcie L. Edwards
Public Utilities General Manager

ATTEST:

____

APPROVED AS TO FORM:

____

33. SIGNATURE PAGE

CITY OF AZUSA

CITY OF AZUSA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 24th day of July, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Azusa)

Appendix B (Azusa)

Appendix C

Appendix D

Appendix F

CITY OF AZUSA

By: Diane Chagnon
Diane Chagnon
Mayor

34. SIGNATURE PAGE

CITY OF BANNING

CITY OF BANNING has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 8th day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Banning)

Appendix C

Appendix D

Appendix F

CITY OF BANNING

By: ______________________
Randy Anstine
City Manager

ATTEST:

____
Marie Calderon, City Clerk

APPROVED AS TO FORM:

____
~~Julie Hayward Biggs~~, City Attorney
Thomas D. Jex, Deputy

35. SIGNATURE PAGE

CITY OF RIVERSIDE

CITY OF RIVERSIDE has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ____ day of _____________, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Riverside)

Appendix B (Riverside)

Appendix C

Appendix D

Appendix F

CITY OF RIVERSIDE
3900 Main Street, 4th Floor
Riverside, California 92522

By:_____________________________
George A. Caravalho, City Manager

ATTEST:

____
City Clerk

APPROVED AS TO FORM:

____
Supervising Deputy City Attorney

36. SIGNATURE PAGE

TRANS-ELECT NTD PATH 15, LLC

TRANS-ELECT NTD PATH 15, LLC has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 28th day of July, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Trans-Elect)

Appendix C

Appendix D

Appendix F

Trans-Elect NTD Path 15, LLC
1850 Centennial Park Drive
Suite 480
Reston, VA 20191

By: ______________________
Robert D. Dickerson
Executive Vice President

37. SIGNATURE PAGE

WESTERN AREA POWER ADMINISTRATION, SIERRA NEVADA REGION

WESTERN AREA POWER ADMINISTRATION, SIERRA NEVADA REGION has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 24th day of July, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Western)

Appendix C

Appendix D

Appendix F

Western Area Power Administration, Sierra Nevada Region
Sierra Nevada Region
114 Parkshore Drive
Folsom, CA 95630-4710

By: ______________________
James D. Keselburg
Regional Manager

38. SIGNATURE PAGE

CITY OF PASADENA

CITY OF PASADENA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ____ day of _______________, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Pasadena)

Appendix B (Pasadena)

Appendix C

Appendix D

Appendix F

City of Pasadena Water and Power Department
150 S. Los Robles, Suite 200
Pasadena, CA 91101

By: ________________________________
Cynthia J. Kurtz
City Manager

39. SIGNATURE PAGE

TRANS BAY CABLE LLC

TRANS BAY CABLE LLC has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 2nd day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Trans Bay Cable LLC)

Appendix C

Appendix D

Appendix F

Trans Bay Cable LLC
c/o Babcock & Brown LP
2 Harrison Street, 6th Floor
San Francisco, CA 94105
Tel: (415) 512-1515
Fax: (415) 267-1500

By: ______________________

David Parquet
Vice President
Trans Bay Cable LLC

APPENDIX A2

List of Entitlements Being Placed Under ISO Operational Control

(Includes only those where PG&E is a service rights-holder)

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Pacific Power & Light, SCE, SDG&E	Transmission Use Agreement –PP&L Rate Schedule with FERC	Transmission	Upon 40 years beginning approx. 1968	
2.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement – PG&E Rate Schedule FERC No. 38	Transmission	8/1/2007	Both entitlement and encumbrance.
3.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan – PG&E Rate Schedule FERC No. 183	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classified as an entitlement since loop flow is reduced or an encumbrance if PG&E is asked to cut.
4.	TANC and other COTP Participants, and WAPA	Owners Coordinated Operations Agreement – PG&E Rate Schedule FERC No. 229	Transmission system coordination, curtailment sharing, rights allocation, scheduling	1/1/2043, or on two years' notice, or earlier if other agreements terminate	Both entitlement and encumbrance
5.	Various – See Attachment A	Western Systems Power Pool Agreement – WSPP Rate Schedule FERC No. 1	Power Sales, transmission	Upon WSPP expiration	Both entitlement and encumbrance.
6.	Vernon (City of)	Transmission Service Exchange Agreement – PG&E Rate Schedule FERC No. 148	Transmission	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for service on COTP

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
1.	California Companies Pacific Intertie Agreement (CCPIA)	PG&E, SDG&E	40	July 31, 2007	• 43% of the California Companies entitlements on the Pacific Intertie.
2.	City-Edison Pacific Intertie D-C Transmission Facilities Agreement	LADWP	448	3/31/2041 or sooner by mutual agreement of the parties.	• Edison owns 50% of the D-C transmission facility. (Per CCPIA, this ownership is part of the California Companies entitlements on the Pacific Intertie).
3.	PP&L Agreement	PP&L, PG&E, SDG&E		2008	• California Companies are entitled to use the entire capacity on the PP&L 500 kV transmission line from Malin to Indian Spring for the term of the agreement. Per CCPIA Edison is entitled to 43% of the capacity available on the Pacific Intertie.
4.	Los Angeles-Edison Exchange Agreement	LADWP	219	May 31, 2025	• 500 MW of bi-directional firm entitlement on the PDCI transmission line.
5.	Owners Coordinated Operations Agreement	PG&E, SCE, SDG&E, WAPA & COTP		SCE's participation terminates on 7/31/07 with CCPIA termination unless as otherwise contemplated by Section 6.3.1 of the Agreement.	• Provides for the continued coordinated operation of the PACI and COTP. The allocation of Available Scheduling Capability between the parties is calculated as specified in the Agreement.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
6.	Pasadena-Edison 230-KV Interconnection and Transmission Agreement	Pasadena	55	8/4/2010	• Goodrich-Gould and Goodrich-Laguna Bell 230 kV transmission line interconnect Edison's system with Pasadena's system at Pasadena's Goodrich Substation. Lines have been re-configured from arrangement shown in contract. • Edison maintains and operates Goodrich 230 kV Substation.
7.	Victorville-Lugo Interconnection Agreement	LADWP	51	2019 or sooner by mutual agreement	• 1950 MW towards Edison, 900 MW towards LADWP. Transfer capability of the interconnection is established through joint technical studies.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
8.	City-Edison Sylmar Interconnection Agreement	LADWP	307	On 5 years notice by either party any time after the termination of the City-Edison Pacific Intertie DC Transmission Facilities Agreement.	• Sylmar-Pardee #1&2, Sylmar-Gould and Sylmar-Eagle Rock 230 kV transmission line interconnections at Sylmar including circuit breakers and busses. Lines have been re-configured from arrangement described in contract. • Edison owns one of the two regulating transformers at Sylmar.
9.	City-Edison Owens Valley Interconnection and interchange Agreement	LADWP	50	On 12 months notice by either party.	• At the request of either party and by mutual agreement, LADWP's and Edison's respective systems interconnected at LADWP's Haiwee 34.5 kV Substation, may be operated in parallel, which normally operates open at Haiwee.
10.	City-Edison 400,000 kVA Interconnection Agreement (Velasco)	LADWP	215	On 3 year written notice by either party.	• Edison's portion of the normally open Laguna Bell-Velasco 230 kV transmission line from Laguna Bell to the point where ownership changes.
11.	Edison-Los Angeles Inyo Interconnection Agreement	LADWP	306	On 5 year advance written notice by either party or by mutual agreement.	• Inyo 230/115 kV Substation, Inyo Phase Shifter, Control-Inyo 115 kV transmission line and 230 kV Tap to LADWP's Owens Gorge-Rinaldi 230 kV transmission line.
12.	Edison-Los Angeles Sepulveda Canyon Power Plant Transmission Service Agreement	LADWP	280	Termination of Sepulveda Canyon Power Plant Interconnection Agreement or sooner by either party giving a one year notice. Should LADWP change rates, SCE has the right to terminate with 60 days written notice.	• 9 MW of transmission service from the high voltage leads of Sepulveda Canyon Power Plant to the 230 kV bus at Sylmar.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
13.	Amended and Restated IID-Edison Mirage 230 kV Interconnection Agreement	IID	314	On one year notice but not prior to the termination date of the IID-Edison Transmission Service Agreement for Alternate Resources.	• Edison's interconnection with IID at Mirage and the point of interconnection on the Devers – Coachella Valley line.
14.	IID Edison Transmission Service Agreement for Alternative Resources	IID		Earlier of Dec 31, 2015, or the termination date of the last Plant Connection Agreement.	• Transmission Service on IID's 230 kV system to transmit the output of QFs resources to Edison's system, via Mirage Substation.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
15.	Four Corners Principles of Interconnected Operation	APS, SRP, EPE, PSNM, TGE	47.0	None	• Generation principles for emergency service. • Edison's facility at Four Corners includes its portion of the Eldorado –Moenkopi from Eldorado to CA/NV boarder of the Eldorado-Moenkopi –Four Corners 500 kV transmission line. • Edison can separate its wholly-owned facilities from parallel operation with others under abnormal operating conditions without prior notice. • Edison can separate its wholly-owned facilities from parallel operation with others for maintenance on reasonable advance notice (see Co-tenancy Agreement for facilities). • Edison has the right to schedule emergency service from each party.
16.	Four Corners Project Co-Tenancy Agreement and Operating Agreement	APS, SRP, EPE, PSNM, TGE	47.2	2016	• Edison has co-tenancy ownership of 32% in the Four Corners 500 kV switchyard, 12% in the 345 kV switchyard and 48% in the 345/500 kV bus-tie transformer bank. • Edison has rights to sufficient capacity in the switchyards and bus-tie transformer bank to permit its entitlement to Four-Corners Project power and energy to be delivered to the point where the Eldorado-Moenkopi-Four Corners transmission line connects to the Four Corners 500 kV Switchyard. • Edison may use any unused capacity in the switchyard for any purpose, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership of the requesting co-owners.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
17.	Navajo Interconnection Principles	USA, APS, SRP, NPC, LADWP, TGE	76	None	• Generation principles for emergency service.
18	Edison – Navajo Transmission Agreement	USA, APS, SRP, NPC, LADWP, TGE	264	5/21/23	• In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency transmission service without a charge. The amount of service provided is proportional to each parties' entitlement to the total capability of the transmission system described above.
19.	ANPP High Voltage Switchyard Agreement	APS, SRP, PSNM, EPE, SCPPA, LADWP	320	2031	• Edison has 21.77% undivided ownership interest as a tenant-in-common in the ANPP High Voltage Switchyard. • Edison has rights to transmit through the ANPP High Voltage Switchyard up to its 15.8% share of generation from ANPP, or a substitute equal amount, plus any other generation up to the extent of its transmission rights in the Palo Verde-Devers 500 kV Transmission Line • Edison has additional rights to use any unused capacity in the ANPP High Voltage Switchyard, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
20.	Mutual Assistance Transmission Agreement	IID, APS, SDG&E	174	In 2034 or sooner by mutual agreement of the parties.	• In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
21.	Midway Interconnection	PG&E	309	July 31, 2007	• Edison's share of 500 kV Midway-Vincent transmission system: – Midway-Vincent #1 – Midway-Vincent #2 – Midway-Vincent #3 from Vincent Substation to mile 53, Tower 1
22.	Amended and Restated Eldorado System Conveyance and Co-Tenancy	NPC, SRP, LADWP	424	July 1, 2006	• Edison's share of Eldorado System Components: • Eldorado Substation: Edison Capacity Entitlement = Eldorado Substation Capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]; • Mohave Switchyard: Edison Capacity Entitlement = 884 MW; • Eldorado – Mohave 500 kV line: (Edison Capacity Entitlement – Eldorado – Mohave 500 kV line capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]); • Eldorado – Mead 230 kV Line Nos. 1 & 2: (Edison Capacity Entitlement = Eldorado – Mead 230 kV Line No. 1 &2 capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Capacity Entitlement [158 MW].

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
23.	WAPA-Edison 161 kV Blythe Substation Interconnection Agreement	WAPA	221	September 30, 2007 or sooner by 3 year advanced notice by either party.	• WAPA's Blythe 161 kV Substation, and Edison's Eagle Mountain-Blythe 161 kV transmission line. • Edison may transmit up to 168 MW through WAPA's Blythe Substation, via the Eagle Mountain-Blythe 161 kV transmission line (Note: FP&L entitled to 96 MW of FTRs due to participation in facility upgrade project).
24.	SONGS Ownership and Operating Agreements	SDG&E, Anaheim, Riverside	321	In effect until termination of easement for plant site.	• Edison's share of SONGS switchyard with termination of its 230 kV transmission lines: – SONGS – Santiago 1 and 2, – SONGS – Serrano, and – SONGS – Chino 230 kV
25.	District-Edison 1987 Service and Interchange Agreement	MWD	443	September 30, 2017 or on five years notice by either party.	• Transmission is owned by District, but is in ISO control area. If not in use by District, or the United States under existing contracts, District's Transmission Line is available to transmit any electric energy to which Edison may be entitled. • Up to 320 MW is required to supply District's Colorado River Aqueduct pump load. • District's Transmission Line is operated by the District as directed by Edison.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

26.	Edison-Arizona Transmission Agreement	APS	282	2/28/2017 or later upon negotiation.	• Edison has ownership-like rights to the 500 kV Transmission line from the Four Corners Project to the Arizona-Nevada border. Edison also owns the 500 kV line from Arizona-Nevada border to Edison's Eldorado substation.
27.	Mead Interconnection Agreement	WAPA	308	May 31, 2017	• Edison has rights to transmit its Hoover power • Edison's facilities include Eldorado-Mead 230 kV #1 and 2 transmission lines. • Edison may request additional firm transmission service rights through Mead Substation subject to availability as determined by WAPA.
28.	Power Purchase Contract Between SCE and Midway-Sunset Cogeneration Company.	Midway-Sunset Cogeneration Company.		5/8/09	• 200 MW of capacity through Midway Substation.
29.	Agreement for Mitigation of Major Loop Flow	Pacificorp, PG&E, SCE	Pacific orp R/S # 298	2/12/2020	• Pacificorp to operate Phase Shifting Transformers on the Sigurd-Glen Canyon and Pinto-Four Corners Transmission Lines in accord with contract.

APPENDIX A.2: SDG&E'S CONTRACT ENTITLEMENTS

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
66-020	California Companies Pacific Intertie Agreement	Edison, PG&E	20	Subject to FERC's approval and any litigation concerning term, no earlier than July 31, 2007.	7% of the California Companies entitlements on the Pacific Intertie, including delivery rights through SCE's system from Sylmar to SONGS (100 MW); and from SONGS to Sylmar (105 MW); from Midway to SONGS (161 MW); and from SONGS to Midway (109MW).
67-012	Pacific Power & Light Agreement	PP&L, PG&E, Edison		Subject to FERC's acceptance and any litigation concerning term, no earlier than 2008.	California Companies entitled to use the entire capacity on the PP&L 500 kV transmission line from Malin to Indian Spring for the term of the agreement. SDG&E is entitled to 7% of the capacity available on the Pacific Intertie.
	Owners Coordinated Operations Agreement	PG&E, Edison, and COTP participants		SDG&E's participation terminates on 7/31/07 with CCPIA termination unless as otherwise contemplated by Section 6.3.1 of the Agreement.	The allocation of Available Scheduling Capability between COTP parties and the Companies Pacific Intertie parties calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	Should a contingency occur in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None.	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey (3 Lines) - Talega (2 lines)

79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy.
78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by CFE of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031.	The parties are obligated to provide mutual switchyard assistance during emergencies to the extent possible. However, in the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E California Transmission System Participation Agreement	IID		June 24, 2051.	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500 kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E -- 85.64%; and IID -- 14.36%.
78-003	APS-SDG&E Arizona Transmission System Participation Agreement	APS		July 31, 2031.	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS -- 11%; SDG&E – 76.22%; IID – 12.78%.

APPENDIX A: CITY OF RIVERSIDE TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	IPP-Adelanto Switching Station	Riverside-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	N-S 195 MW S-N 142 MW
2.	Marketplace Substation-Adelanto	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
3.	Westwing-Mead-Marketplace 500 kV	Riverside-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	12 MW
4.	Marketplace-McCullough 500 kV	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		31-Oct-30 31-Oct-30	118 MW 12 MW
5.	Adelanto-Victorville/Lugo	Riverside-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	118 MW
6.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Base Capacity Transmission Service Agreement		See Note 2	122 MW
7.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Additional Capacity Transmission Service Agreement		See Note 3	73 MW
8.	IPP-Mona Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	220 MW
	IPP-Gonder Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	31 MW
9.	Nevada-Oregon Border-Sylmar	Riverside-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	23 MW
10.	San Onofre-Vista	Riverside-SCE	To Vista	San Onofre Nuclear Generating Station Firm Transmission Service Agmt.		See Note 5	42 MW
11.	Mead 230 kV-Vista	Riverside-SCE	To Vista	Hoover Firm Transmission Service Agreement		See Note 6	30 MW
12.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Intermountain Power Project Firm Transmission Service Agreement		See Note 7	156 MW
13.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Palo Verde Nuclear Generating Station Firm Transmission Service Agmt.		See Note 8	12 MW

Notes

1. Agreement terminates on: (i) removal of Mead-Adelanto Project from Service; or (ii) removal of Los Angeles-SCE interconnection at Victorville/Lugo.
2. Agreement terminates on: (i) June 15, 2027; or (ii) the date Riverside interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Riverside interconnects at Adelanto Switching Station; or (iii) 5-year's notice by LADWP.
4. Agreement terminates on: (i) termination of LADWP's rights to the Northern Transmission System; or (ii) termination of the IPP Additional Capacity Agreement.
5. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in San Onofre Nuclear Generating Station Units 2 and 3; or (iii) unacceptable FERC modification.
6. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in the Boulder Canyon Project (Hoover); or (iii) unacceptable FERC modification.
7. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in the Intermountain Power Project; or (iii) unacceptable FERC modification.
8. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in the Palo Verde Nuclear Generating Station; or (iii) unacceptable FERC modification.

Appendix A
Trans Bay Cable, LLC
Transmission Entitlements

Trans Bay Cable Project Facilities

Trans Bay Cable LLC (TBC) will develop, finance and construct a high voltage, direct current transmission line of approximately fifty-five miles in length and associated facilities to establish a direct connection between Pacific Gas and Electric Company's (PG&E's) Pittsburg Substation located at a site adjacent to the City of Pittsburg, California in Contra Costa County to PG&E's Potrero Substation within the City of San Francisco (the Project). The transmission line will consist of an approximately 7,000-ton bundled cable consisting of a transmission cable, a fiber optic communications cable and a metallic return. The underwater portion of the transmission line will be laid by a ship or barge with special equipment in a single trench underneath San Francisco Bay. The remaining length of the transmission line (most likely a few hundred yards at either end of the line) will be buried underground, either through directional drilling or laid in a trench. In addition, the Project will involve the construction of two converter stations near each of the PG&E Substations to convert the alternating current received at the Pittsburg Substation to direct current and then back to alternating current at the Potrero Substation.

TBC will provide the funding for (i) the development and construction of the Project, (ii) the acquisition of all needed real property and other interests and (iii) the reimbursement of the on-going operation and maintenance expenses of the Project. In return and pursuant to the Operating Memorandum among TBC, the City of Pittsburg and Pittsburg Power Company which was accepted for filing by the Federal Energy Regulatory Commission (112 FERC ¶ 61,095, *order granting clarification,* 114 FERC ¶ 61,031), TBC will be granted 100% of the Entitlements to the transmission capacity created by the Project and all financial benefits associated with the Entitlements. In accordance with the TCA and the TO Tariff, TBC will transfer the Entitlements created by the Project to ISO Operational Control at the time the Project enters service.

PG&E APPENDIX B

List of Encumbrances on Lines and Facilities, and Entitlements Being Placed Under ISO Operational Control (per TCA Appendix A1 & A2)[1]

(Includes only those where PG&E is a service provider)

Abbreviations Used:		
	CDWR	= California Department of Water Resources
	SCE	= Southern California Edison Company
	SDG&E	= San Diego Gas & Electric Company
	SMUD	= Sacramento Municipal Utility District
	TANC	= Transmission Agency of Northern California
	WAPA	= Western Area Power Administration

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Bay Area Rapid Transit	Service Agreement Nos. 42 and 43 to FERC Electric Tariff, First Revised Volume No. 12	Network Integration Transmission Service Agreement and Network Operating Agreement - OAT	10/1/2016	
2.	CDWR	Comprehensive Agreement – PG&E Rate Schedule FERC No. 77	Interconnection and Transmission	12/31/2014	Transmission Related Losses
3.	CDWR	Etiwanda Power Plant Generation Exchange – PG&E Rate Schedule FERC No. 169	Power exchanges	Evergreen, or on 5 years notice	
4.	Dynegy Power Services	Control Area Transmission Agreement – PG&E Rate Schedule FERC No. 224	Transmission and various other services	Terminated 12/31/01. PG&E filing of FERC termination pending submittal.	

[1] The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
5.	DOE Laboratories, WAPA	PG&E/WAPA/DOE-SF 10/30/98 Settlement Agreement – PG&E Rate Schedule FERC No. 147	Transmission Service	3/31/2009	
6.	Midway-Sunset Co-Generation	Cogeneration Project Special Facilities – PG&E Rate Schedule FERC No. 182	Interconnection, transmission	1/1/2017	
7.	Minnesota Methane	Service Agreement No. 1, under FERC Electric Tariff, First Revised Volume No. 12	Firm Point-to-Point Transmission Service - OAT	10/1/2016	Effective 10/1/96
8.	Modesto Irrigation District	Interconnection Agreement – PG&E Rate Schedule FERC No. 116	Interconnection, transmission, power sales	4/1/2008	Power sales are coordination sales – voluntary spot sales
9.	NCPA, CSC, CDWR	Castle Rock-Lakeville CoTenancy Agreement – PG&E Rate Schedule FERC No. 139	Transmission facilities maintenance	Evergreen, or 1 year notice after 1/1/2015	
10.	Path 15 Operating Instructions Settlement, Revision 1 – Various, see FERC Docket No. ER04-61-000	Exhibit B-1 to this Appendix B to the TCA	Implements curtailment priorities consistent with various Existing Transmission Contracts. Establishes Path 15 Facilitator role for PG&E.	Upon request by PG&E after 1/1/05, subject to FERC acceptance.	
11.	Power Exchange	Control Area Transmission Service Agreement – PG&E Rate Schedule FERC No. 186	Transmission and various other services	Terminated 3/1/2000. PG&E filing of FERC termination pending submittal	
12.	Puget Sound Power & Light	Capacity and Energy Exchange – PG&E Rate Schedule FERC No. 140	Power exchanges	Terminates on 5 years' advance notice.	

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
13.	San Francisco (City and County of)	Interconnection Agreement - PG&E Rate Schedule FERC No. 114	Interconnection, transmission and supplemental power sales	7/1/2015	Power sales are Firm Partial Requirements
14.	Santa Clara (City of)	Mokelumne Settlement and Grizzly Development Agreement – PG&E Service Agreement No. 20 under FERC Electric Tariff Sixth Revised Volume No. 5	Transmission, power sales	1/1/2034	
15.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement – PG&E Rate Schedule FERC No. 38	Transmission service	8/1/2007	Both entitlement and encumbrance.
16.	SCE, Montana Power Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan – PG&E Rate Schedule FERC No. 221	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classified as an entitlement since loop flow is reduced or an encumbrance if PG&E isasked to cut.
17.	Shelter Cove	Interconnection Agreement – PG&E Rate Schedule FERC No. 198	Distribution	6/30/2006	Effective 8/15/96
18.	Sierra Pacific	Interconnection Agreement – PG&E Rate Schedule FERC No. 72	Interconnection and support services	Evergreen, or 3 years notice	
19.	SMUD	Interconnection Agreement – PG&E Rate Schedule FERC No. 136	Interconnection and transmission services	12/31/2009	
20.	SMUD	EHV Transmission Agreement – PG&E Rate Schedule FERC No. 37	Transmission	Terminated 1/1/2005 (appeal pending)	
21.	SMUD	Camp Far West Transmission Agreement – PG&E Rate Schedule FERC No. 91	Transmission	No notice of termination filed with FERC	

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
22.	SMUD	Slab Creek Transmission Agreement – PG&E Rate Schedule FERC No. 88	Transmission	No notice of termination filed with FERC	
23.	TANC and other COTP Participants, and WAPA	Owners Coordinated Operations Agreement – PG&E Rate Schedule FERC No. 229	Transmission system coordination, curtailment sharing, rights allocation, scheduling.	1/1/2043, or on two years' notice, or earlier if other agreements terminate	Both entitlement and encumbrance
24.	TANC and other COTP Participants	COTP Interconnection Rate Schedule – PG&E Rate Schedule FERC No. 144	Interconnection	Upon termination of COTP	
25.	TANC	Midway Transmission Service / South of Tesla Principles – PGE& Rate Schedule FERC No. 143	Transmission, curtailment priority mitigation,* replacement power	Same as the COTP Interim Participation Agreement, subject to exception	
26.	Turlock Irrigation District	Interconnection Agreement – PG&E Rate Schedule FERC No. 213	Interconnection, transmission	4/1/2008, subject to exception	
27.	Vernon (City of)	Transmission Service Exchange Agreement – PG&E Rate Schedule FERC No. 148	Transmission service	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for Vernon's COTP rights
28.	WAPA	San Luis Unit – Contract No. 2207A – PG&E Rate Schedule FERC No. 227 (superseding Original Tariff Sheet Nos. 104 through 137 of PG&E Rate Schedule FERC No. 79)	Transmission	4/1/2016	

* Includes use of PG&E's DC Intertie or PDCI for prespecified mitigation of curtailments over Path 15.

Ref.#	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
29.	WAPA	New Melones – Contract No. 8-07-20-P0004 – PG&E Rate Schedule FERC No. 60	Transmission	6/1/2032	Per WAPA, commercial operation date for New Melones was 6/1/82

Lien Mortgage

The lien of the First and Refunding Mortgage dated December 1, 1920 between PG&E and BNY Western Trust Company, as trustee, as amended and supplemented and in effect of the date hereof (the "PG&E Mortgage"). The transfer of Operation Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the PG&E Property which would be prior to the lien of the PG&E Mortgage; however, no consent of the trustee under the PG&E Mortgage is require to consummate the transfer of Operation Control to the ISO pursuant to this Agreement.

TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
1.	Devers - Mirage / Coachella 230 kV	IID	SCE to IID	Firm Transmission Service Agreement	268	On 3-year notice	100 MW May-October, 50 MW rest of the year.
2.	Devers - ISO Grid Take Out Point serving Banning	Banning	To Banning	1995 San Juan Unit 3 Firm Transmission Service Agreement	381	Earlier of termination of Banning's interest in San Juan Unit 3 or Banning's 1-year notice given after 1/1/03	15 MW
3.	Devers-- Vista	Colton	To Vista	1995 San Juan Unit 3 Firm Transmission Service Agreement	365	Earlier of termination of Colton's interest in San Juan Unit 3 or Colton's 1-year notice given after 1/1/03	14.043 MW
4.	Hinds - Vincent	MWD	Bi-dir.	District-Edison 1987 Service and Interchange Agreement	443	The earlier of either (1) the term of MWD's Hoover Electric Service Contract (DE-MS65-86WP39583) expected to be 9/30/2017 or (2) five-year notice	110 MW

Footnotes:
1. The following is an additional encumbrance that does not fit into the format for existing contract encumbrances. The additional encumbrance is: The lien of the Trust Indenture dated as of October 1, 1923, between Edison and Harris Trust and Savings Bank and Pacific-Southwest Trust & Savings Bank (D. G. Donovan, successor trustee), as trustees ("the Edison Indenture"). The transfer of control to the ISO pursuant to this Agreement (i) does not require any consent from the trustees under the Edison Indenture, (ii) shall not be deemed to create any lien or charge on the Edison Transmission Assets that would be prior to the lien of the Edison Indenture, and (iii) shall not otherwise impair the lien of the Edison Indenture.
2. The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
5.	Eldorado-Vincent	CDWR	Bi-dir.	Firm Transmission Service Agreement (Eldorado-Vincent)	113	Earlier of date that a) CDWR has obtained for replacement transmission service; b) CDWR is no longer entitled to Reid Gardner Unit 4 output; c) 12/31/2020; or, d) Reid Gardner Unit 4 is permanently retired from service.	235 MW
6.	Eldorado / Mohave - Lugo	LADWP	Bi-dir.	Victorville - Lugo Interconnection Agreement	51	11/20/ 2019 or sooner by mutual agreement	Edison is required to provide capacity to LADWP equal to the product of LA's Capacity Share and the deemed capacity of the transmission system consisting of Mohave-Lugo, Mohave-Eldorado, Eldorado-Lugo, Eldorado-McCullough, McCullough-Victorville lines, and Victorville-Lugo 500 kV transmission lines.
7.	Moenkopi - Eldorado	USA, APS, SRP, NPC, LADWP, TGE	Bi-dir.	Edison - Navajo Transmission Agreement	264	5/21/23	In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency service transmission rights without a charge.
8.	Mohave – Eldorado	LADWP, NPC, SRP	to Eldorado	Amended and RestatedEldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425	7/1/06	If Mohave-Eldorado line is curtailed, pro-rata back up is provided on Mohave-Lugo and Eldorado-Lugo lines. If Mohave-Lugo is curtailed, pro-rata back-up is provided on Mohave-Eldorado. Amount of back up capacity is up to participant's Mohave Capacity Entitlement. For curtailment purposes, Capacity Entitlements are: Edison-884 MW; LADWP-316 MW; NPC-222 MW;SRP-158 MW.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
9.	Eldorado - Mead	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425	7/1/06	If Eldorado-Mead lines are curtailed, line capacity is allocated pro rata in proportion to the following Capacity Entitlements: NPC-222 MW; SRP-158 MW; LADWP – 0 MW; Edison Capacity Entitlement is equal to entire capacity of the Eldorado-Mead Line Nos. 1&2 minus NPC Capacity Entitlement minus SRP Capacity Entitlement.
10.	Mead - Mohave	NPC	To Mohave	Amended and Restated Agreement for Additional NPC Connection to Mohave Project	426	Co-terminous with Mohave Project Plant Site Conveyance and Co-Tenancy Agreement	Up to 222 MW of Back-up transmission service.
11.	Mead - ISO Grid Take Out Point serving Banning	Banning	E-W	Hoover Firm Transmission Service Agreement	378	Earliest of: Banning's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	2 MW
12.	Mead - Rio Hondo	Azusa	Bi-dir	Sylmar Firm Transmission Service Agreement	375	Earliest of: Azusa's 1-year notice given after 1/1/02, or termination of Azusa's interest in San Juan #3	8 MW
13.	Mead - Rio Hondo	Azusa	E-W	Hoover Firm Transmission Service Agreement	372	Earliest of: Azusa's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	4 MW
14.	Mead - Vista	Colton	E-W	Hoover Firm Transmission Service Agreement	361	Earliest of: Colton's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	3 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
15.	Mead - Riverside	Riverside	E-W	Hoover Firm Transmission Service Agreement	390	180 day notice by Riverside or termination of WAPA Service Contract	30 MW
16.	Mead - Laguna Bell	Vernon	Bi-dir	Mead Firm Transmission Service Agreement	207	Upon mutual agreement or termination of Hoover Power Sales Agreement	26 MW
17.	Mead - Mountain Center	AEPCO	E-W	Firm Transmission Service Agreement	131	7/1/21 or on 10 years notice	10 MW
18.	Palo Verde - Devers	LADWP	Bi-dir	Exchange Agreement	219	Earliest of (i) in-service of DPV#2 line, (ii) the in-service date of any other new transmission line connecting Palo Verde to Devers in which LADWP has obtained an ownership interest or entitlement, (iii) the date DPV#1 is permanently removed from service, (iv) 4 years after CPUC approval to transfer DPV#2 rights of way to LADWP or (v) 12 months notice by LADWP.	368 MW
19.	Palo Verde - Sylmar	LADWP	Bi-dir.	Exchange Agreement	219	5/31/2012	100 MW
20.	Sylmar - Devers	LADWP	Bi-dir	Exchange Agreement	219	When DPV#1 is removed from service, or if DPV#2 is built, the date DPV#2 is removed from service	368 MW
21.	Palo Verde - Devers Devers - Valley Valley - Serrano Serrano - SONGS	IID, APS, SDG&E	Bi-Dir.	Mutual Assistance Transmission Agreement	174	On 2034 or sooner by agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in an operating bulletin.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
22.	Midway - Vincent 500 kV	PG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	633 MW
23.	Midway - SONGS	SDG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	161 MW
24.	Midway - Vincent 500 kV	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25 or Pacific AC Intertie Agreement termination on 7-31-2007	320 MW
25.	Midway - Vincent 500 kV	PG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	655 MW
26.	Midway - SONGS	SDG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20- SDG&E)	7/31/07	109 MW
27.	Midway - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: term of PG&E Transmission Agreement, or 12/29/42 (50 yrs).	60 MW until 1/1/00, 60MW after 12/31/07
28.	Pacific AC 500 kV Intertie	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25 or Pacific AC Intertie Agreement termination on 7-31-2007	320 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
29.	SONGS - Vista	Riverside	To Vista	SONGS 2 & 3 Firm Transmission Service Agreement	393	180 day notice by Riverside or SONGS Participation termination	42 MW
30.	Victorville/Lugo - Midway	MSR	S-N	Firm Transmission Service Agreement (Victorville/Lugo-Midway)	339	Earlier of: five-year notice by MSR, or life of Mead-Adelanto 500 kV Transmission Project	150 MW
31.	Victorville/Lugo - Vista	Riverside	To Vista	Intermountain Power Project Firm Transmission Service Agreement	391	180 day notice by Riverside or IPP Participation termination	156 MW
32.	Victorville/Lugo - Rio Hondo	Azusa	To Rio Hondo	PVNGS Firm Transmission Service Agreement	373	Earliest of: Azusa's 1-year notice given after 1/1/02, termination of PVNGS entitlement, or termination of PVNGS participation.	4 MW
33.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	To Banning	PVNGS Firm Transmission Service Agreement	379	Earliest of: Banning's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW
34.	Victorville/Lugo - Vista	Colton	To Vista	PVNGS Firm Transmission Service Agreement	362	Earliest of: Colton's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
35.	Victorville/Lugo - Vista	Riverside	To Vista	PVNGS Firm Transmission Service Agreement	392	Earliest of: Riverside's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	12 MW
36.	Victorville/Lugo –Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360	Terminates with permanent removal of Mead-Adelanto from service	11 MW
37.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	Bi-dir.	Sylmar Firm Transmission Service Agreement	380	Earliest of Banning's 1-year notice given after 1/1/02, or termination of Bannings interest in San Juan #3.	5 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
38.	Victorville/Lugo - Rio Hondo	Azusa	to Rio Hondo	Pasadena FTS	374	Earliest of Azusa's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	14 MW
39.	Victorville/Lugo - Vista	Colton	to Vista	Pasadena FTS	363	Earliest of Colton's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	18 MW
40.	Sylmar - Rio Hondo	Azusa	To Rio Hondo	1995 San Juan Unit 3 FTS Agreement	376	Earlier of: termination of Azusa's interest in San Juan Unit #3 or Azusa's 1-year notice given after 1/1/02	10 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
41.	Sylmar - Goodrich	Pasadena	Bi-dir	Pasadena-Edison 230-kV Interconnection and Transmission Agreement	55	8/4/10	200 MW; Edison also responsible for delivery of up to 15 MW of Azusa Hydro Energy to Pasadena at Goodrich
42.	Sylmar - Vista	Colton	Bi-dir.	Sylmar Firm Transmission Service Agreement	364	Earliest of: Colton's 1-year notice given after 1/1/02, or termination of Idaho service contract.	3 MW
43.	Sylmar - Midway	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Termination of Vernon COTP Ownership	93 MW until 1/1/00, 93MW after 12/31/07
44.	Sylmar - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Termination of Vernon COTP Ownership	60 MW
45.	Sylmar - SONGS	SDG&E	To SDG&E	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	100 MW
46.	Sylmar - SONGS	SDG&E	To Sylmar	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	105 MW
47.	Sylmar - Mead	PG&E	To Mead.	Edison-PG&E Transmission Agreement	256	7/31/07	Up to 200 MW of FTS.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
48.	Hoover - Mead	WAPA	Bi-dir.	Lease of Two 230-kV Transmission Lines Between Hoover Power Plant and Mead Substation	304	9/30/2017 or upon 3-years' notice by WAPA; WAPA entitled to renew through life of Hoover.	Entire capacity leased to WAPA.
49.	Calectric — Vincent	CDWR	To Vincent	Amended and Restated CDWR Devil Canyon Power Plant Additional Facilities and Firm Transmission Service Agreement	421	Life of Plant	120 MW
50.	Mojave Siphon (Vista) - Vincent	CDWR	To Vincent	CDWR Mojave Siphon Additional Facilities and Firm Transmission Service Agreement	342	Life of Plant	28 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
51.	Blythe - Cibola, & Ehrenberg	APS	To APS Load	Firm Transmission Service (Blythe Accounts)	348	Upon 3-year notice by APS, or 10 year notice by Edison	Presently 5.1 MW, 7 MW max.

APPENDIX B.2

SDG&E's List of Contract Encumbrances[1]/[2]

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey (3 lines) - Talega (2 lines)
79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy without charge.

1 An additional encumbrance pertaining to Local Furnishing Bonds that does not fit into the format for existing contract encumbrances is set forth at pages SDG&E App. B-1 through B-3 hereof.

2 An additional encumbrance pertaining to SDG&E's lien of Mortgage and Deed of Trust that does not fit into the format for existing contract encumbrances is set forth at page SDG&E App. B-4 hereof.

78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031	In the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E Transmission System Participation Agreement	IID		June 24, 2051	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E -- 85.64%; and IID -- 14.36%.
78-003	APS-SDG&E Transmission System Participation Agreement	APS		July 31, 2031	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS -- 11%; SDG&E – 76.22%; IID – 12.78%.
QFD000.016	Power Sale Agreement between SDG&E-City of Escondido for the Rincon Indian Reservation	City of Escondido	76	Agreement to be terminated effective upon FERC acceptance of Notice of Termination.	Obligates SDG&E to sell and deliver electricity at stated prices to the City of Escondido for resale to the United States Indian Services at the Rincon Indian Reservation.

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO TRANSMISSION MAINTENANCE STANDARDS

TABLE OF CONTENTS

1. DEFINITIONS[1]

Availability - A measure of time a Transmission Line Circuit under ISO Operational Control is capable of providing service, whether or not it actually is in service.

Availability Measures - Within each Voltage Class in a calendar year: 1) the average Forced Outage$^{(IMS)}$ frequency for all Transmission Line Circuits, 2) the average accumulated Forced Outage$^{(IMS)}$ duration for only those Transmission Line Circuits with Forced Outages$^{(IMS)}$, and 3) the proportion of Transmission Line Circuits with no Forced Outages$^{(IMS)}$.

Availability Measure Targets - The Availability performance goals jointly established by the ISO and a PTO for that PTO's Transmission Facilities.

Forced Outage$^{(IMS)}$ – An event that occurs when a Transmission Facility is in an Outage$^{(IMS)}$ condition for which there is no Scheduled Outage$^{(IMS)}$ request in effect.

ISO Transmission Maintenance Standards - The Maintenance standards set forth in this Appendix C.

[1] A term followed by the superscript "(IMS)" denotes a term which has a special, unique definition in this Appendix C.

Maintenance - Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities performed with respect to Transmission Facilities.

Maintenance Practices - A confidential description of methods used by a PTO, and adopted by the ISO, for the Maintenance of that PTO's Transmission Facilities.

Maintenance Procedures – Documents developed by the Transmission Maintenance Coordination Committee for use by the ISO and the PTOs to facilitate compliance with the ISO Transmission Maintenance Standards. These documents shall serve as guidelines only.

Outage(IMS) - Any interruption of the flow of power in a Transmission Line Circuit between any terminals under ISO Operational Control.

PTO - A Participating TO as defined in Appendix D of the Transmission Control Agreement.

Scheduled Outage(IMS) - The removal from service of Transmission Facilities in accordance with the requirements of Section 7.1 of the Transmission Control Agreement and the applicable provisions of the ISO Tariff and ISO Protocols.

Station – Type of Transmission Facility used for such purposes as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities - All equipment and components transferred by a PTO to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and associated facilities.

Transmission Line Circuit - The continuous set of transmission conductors, under the ISO Operational Control, located primarily outside of a Station, and apparatus terminating at interrupting devices, which would be isolated from the transmission system following a fault on such equipment.

Transmission Maintenance Coordination Committee ("TMCC") - The committee described in Section 7 of this Appendix C.

Voltage Class - The voltage to which operating, performance, and Maintenance characteristics are referenced. Voltage Classes are defined as follows:

Voltage Class	Range of Nominal Voltage
69 kV	≤ 70 kV
115 kV	110 - 161 kV
230 kV	200 - 230 kV
345 kV	280 - 345 kV
500 kV	500 kV
HVDC	HVDC

Capitalized terms, not expressly defined above, are used consistently with the definitions provided in the Transmission Control Agreement and the ISO Tariff.

2. INTRODUCTION

This Appendix C delineates the ISO Transmission Maintenance Standards and has been developed through a lengthy consensus building effort involving initially the ISO Maintenance Standards Task Force, and currently the TMCC.

Flexibility in establishing these ISO Transmission Maintenance Standards is implicit in the goal of optimizing Maintenance across a system characterized by diverse environmental and climatic conditions, terrain, equipment, and design practices. To provide for flexibility while ensuring the reasonableness of each PTO's approach to Maintenance, each PTO will prepare its own Maintenance Practices that shall be consistent with the requirements of these ISO Transmission Maintenance Standards. The effectiveness of each PTO's Maintenance Practices will be gauged through the

Availability performance monitoring system. Each PTO's adherence to its Maintenance Practices will be assessed through an ISO review.

In developing these ISO Transmission Maintenance Standards, both the ISO Maintenance Standards Task Force and TMCC determined that it is impractical to develop and/or impose on the PTOs a single uniform set of prescriptive practices delineating conditions or time-based schedules for various Maintenance activities that account for the myriad of equipment, operating conditions, and environmental conditions within the ISO Controlled Grid. For this reason, these ISO Transmission Maintenance Standards provide requirements for the PTOs in preparing their respective Maintenance Practices.

2.1. OBJECTIVE

This Appendix C provides for a high quality, safe, and reliable ISO Controlled Grid by meeting the following objectives:

- Ensuring that the Availability performance levels inherent to the Transmission Facilities are maintained,
- Restoring Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Economically extending the useful life of the Transmission Facilities while maintaining inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum reasonable total cost for Maintenance with the intent of minimizing customer impacts.

2.2. AVAILABILITY

ISO Controlled Grid reliability is a function of a complex set of variables, including accessibility of alternative paths to serve Load, Generating Unit availability, Load forecasting and resource planning; speed, sophistication and coordination of protection systems; and the Availability of Transmission Line Circuits owned by the PTOs. Availability Measures have been chosen as the principal determinant of each PTO's Maintenance effectiveness.

When using Availability Measures as a general gauge of Maintenance effectiveness, several things must be considered to avoid misinterpreting performance. Availability is a function of several variables, including Transmission Facility Maintenance, initial design, extreme exposure, capital improvements, and improvements in restoration practices. These factors should be taken into account when assessing Availability Measures and Maintenance effectiveness. It is important to consider that Maintenance is one of many variables that impact changes in Availability. For example, certain Forced Outages[(IMS)] that impact Availability may be due to events that generally cannot be controlled by Maintenance.

If Availability Measures are either improving or declining, it is important to investigate the cause(s) and any trends that are causing change before drawing conclusions. If Maintenance is being performed by a PTO consistent with Good Utility Practice, increasing Maintenance activities by a significant order may not result in a corresponding increase in Availability and if Maintenance is not performed consistent with Good Utility Practice, Availability may decline. Thus, while Maintenance is important to ensure Availability, unless a PTO fails to perform Maintenance on a basis consistent with Good Utility Practice, significant increases in Maintenance activities will generally not lead to substantial improvements in Availability and associated ISO Controlled Grid reliability.

A variety of techniques can be used to monitor Maintenance effectiveness. However, techniques that do not account for random variations in processes have severe limitations in that they may yield inconsistent and/or erroneous assessments of Maintenance effectiveness. To account for random/chance variations while enabling monitoring for shifts and trends, control charts have been widely accepted and utilized. Control charts are statistically based graphs which illustrate both an expected range of performance for a particular process based on historical data, and discrete measures of recent performance. The relative positions of these discrete measures of recent performance and their relationship to the expected range of performance are used to gauge Maintenance effectiveness.

To enhance the use of Availability Measures as a gauge of Maintenance effectiveness, it is necessary to exclude certain types of Outages$^{(IMS)}$. These excluded Outages$^{(IMS)}$, as set forth in more detail in Section 4.1.3 of this Appendix C, are:

- Scheduled Outages$^{(IMS)}$;
- Outages$^{(IMS)}$ classified as "Not a Forced Outage" in the Maintenance Procedures;
- Forced Outages$^{(IMS)}$ caused by events originating outside the PTO's system; or
- Forced Outages$^{(IMS)}$ demonstrated to have been caused by earthquakes.

Additionally, as described in Section 4.1.2 of this Appendix C, the Forced Outage$^{(IMS)}$ duration used to calculate the Availability control charts has been capped at 72 hours so that excessively long Forced Outages$^{(IMS)}$ do not skew the data as to detract from the meaningfulness and interpretation of the control charts for accumulated Forced Outage$^{(IMS)}$ duration. This is not to say that an excessively long Forced Outage$^{(IMS)}$ is not a concern. Rather, such Forced Outages$^{(IMS)}$ should be investigated to assess the reasons for their extended duration.

Establishing Availability Measures requires each PTO to use separate control charts for each Voltage Class. Existing Forced Outage$^{(IMS)}$ data contains significant differences in the Availability between Voltage Classes and between PTOs. These differences may be attributable to factors such as the uniqueness of operating environments, Transmission Facility designs, and PTO operating policies. Regardless of the cause of these differences, review of the Forced Outage$^{(IMS)}$ data makes it eminently apparent that differences are such that no single set of control chart parameters for a particular Voltage Class could be applied to all PTOs.

Three types of control charts are utilized to provide a complete representation of historical Availability Measures, and to provide a benchmark against which future Availability Measures can be gauged. The three types of control charts for each PTO and Voltage Class are:

- The annual average Forced Outage$^{(IMS)}$ frequency for all Transmission Line Circuits;
- The annual average accumulated Forced Outage$^{(IMS)}$ duration for those Transmission Line Circuits which experience Forced Outages$^{(IMS)}$; and
- The annual proportion of Transmission Line Circuits that experienced no Forced Outages$^{(IMS)}$.

These three control charts assist the ISO and PTOs in assessing the Maintenance effectiveness of each Voltage Class over time. To accommodate this process on a cumulative basis, data is made available to the ISO by each PTO at the beginning of each new calendar year to assess past calendar years.

2.3. MAINTENANCE DOCUMENTATION REQUIREMENTS

Two specific requirements regarding Maintenance documentation are incorporated into these ISO Transmission Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance Practices to the ISO. Second, these standards require that each PTO retain Maintenance records as set forth in Section 6.1 of this Appendix C and make those records available to the ISO as set forth in the Maintenance Procedures, in order to demonstrate compliance with each element of its Maintenance Practices.

2.4. AVAILABILITY DATA STANDARDS

To facilitate processing Forced Outage(IMS) data for the Availability Measures, and to enable consistent and equitable interpretation of PTO Maintenance records by the ISO, these standards address the need for data recording and reporting. The TMCC has also developed standardized formats for transmitting Forced Outage(IMS) data to the ISO for the Availability Measures. These standard formats are provided in the Maintenance Procedures. To facilitate review of the data by the ISO, the TMCC has developed a standard Availability Measures reporting system detailed in the Maintenance Procedures and in Section 4 of this Appendix C. This system will provide for consistent gathering of information that can be used as the basis for analyzing Availability Measures trends.

3. FACILITIES COVERED BY THESE ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO Transmission Maintenance Standards set forth in this Appendix C shall apply to all Transmission Facilities. Each PTO shall maintain its Transmission Facilities in accordance with its Maintenance Practices as adopted by the ISO in accordance with these ISO Transmission Maintenance Standards.

4. AVAILABILITY MEASURES

4.1. CALCULATION OF AVAILABILITY MEASURES FOR INDIVIDUAL TRANSMISSION LINE CIRCUITS

4.1.1 FREQUENCY AND DURATION

The calculation of the Availability Measures will be performed utilizing Forced Outage$^{(IMS)}$ data through December 31st of each calendar year. Separate Forced Outage$^{(IMS)}$ frequency and accumulated Forced Outage$^{(IMS)}$ duration Availability Measures shall be calculated as follows for each Transmission Line Circuit under ISO Operational Control within each Voltage Class. The calculations shall be performed annually for each of the Transmission Line Circuits utilizing all appropriate Forced Outage$^{(IMS)}$ data for the calendar year in question.

Forced Outage$^{(IMS)}$ Frequency:

The Forced Outage$^{(IMS)}$ frequency (f_{ik}) of the i^{th} Transmission Line Circuit shall equal the total number of Forced Outages$^{(IMS)}$ that occurred on the i^{th} Transmission Line Circuit during the calendar year "k". See Notes 1 and 2.

NOTES:

1. Multiple momentary Forced Outages$^{(IMS)}$ on the same Transmission Line Circuit in the span of a single minute shall be treated as a single Forced Outage$^{(IMS)}$ with a duration of one minute. When the operation of a Transmission Line Circuit is restored following a Forced Outage$^{(IMS)}$ and the Transmission Line Circuit remains operational for a period exceeding one minute, i.e., 61 seconds or more, followed by another Forced Outage$^{(IMS)}$, then these should be counted as two Forced Outages$^{(IMS)}$. Multiple Forced Outages$^{(IMS)}$ occurring as a result of a single event should be handled as multiple Forced Outages$^{(IMS)}$ only if subsequent operation of the Transmission Line Circuit between events exceeds one minute. Otherwise they shall be considered one continuous Forced Outage$^{(IMS)}$.

2. If a Transmission Line Circuit, e.g., a new Transmission Line Circuit, is only in service for a portion of a calendar year, the Forced Outage$^{(IMS)}$ frequency and accumulated duration data shall be treated as if the Transmission Line Circuit had been in service for the entire calendar year, i.e., the Forced Outage$^{(IMS)}$ data for that Transmission Line Circuit shall be handled the same as those for any other Transmission Line Circuit.

Accumulated Forced Outage$^{(IMS)}$ Duration:

The accumulated Forced Outage$^{(IMS)}$ duration in minutes shall be calculated as follows for each of the Transmission Line Circuits having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year "k":

$$d_{ik} = \sum_{j=1}^{f_{ik}} o_{ijk}$$

where

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ (total number of Forced Outage$^{(IMS)}$ minutes) for the "ith" Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year "k".

f_{ik} = Forced Outage$^{(IMS)}$ frequency as defined above for calendar year "k".

o_{ijk} = duration in minutes of the "jth" Forced Outage$^{(IMS)}$ which occurred during the "kth" calendar year for the "ith" Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages$^{(IMS)}$ shall be capped as described in Section 4.1.2 of this Appendix C for the purposes of calculating the Availability Measures. In addition, certain types of Outages$^{(IMS)}$ shall be excluded from the calculations of the Availability Measures as described in Section 4.1.3 of this Appendix C.

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Forced Outage$^{(IMS)}$ data reporting schemes, the PTO shall notify the ISO at the time of the change. In its annual report to the ISO, the PTO shall provide recommendations regarding if and how the Availability Measures and Availability Measure Targets should be modified to ensure that they (1) remain consistent with the modified Transmission Line Circuit identification or Forced Outage$^{(IMS)}$ data reporting scheme, and (2) provide an appropriate gauge of Availability.

4.1.2. CAPPING FORCED OUTAGE(IMS) DURATIONS

The duration of each Forced Outage(IMS) which exceeds 72 hours (4320 minutes) shall be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage(IMS) duration.

4.1.3. EXCLUDED OUTAGES (IMS)

The following types of Outages(IMS) shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- Scheduled Outages(IMS)
- Outages(IMS) classified as "Not a Forced Outage" in the Maintenance Procedures.

- Forced Outages(IMS) which: (1) were caused by events outside the PTO's system including Outages(IMS) which originate in other TO systems, other electric utility systems, or customer equipment, or (2) are Outages(IMS) which can be demonstrated to have been caused by earthquakes.

4.2. AVAILABILITY MEASURE TARGETS

The Availability Measure Targets described herein shall be phased in over a period of five calendar years beginning on the date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement. The adequacy of each PTO's Availability Measures shall be monitored through the use of charts. These charts, called control charts as shown in Figure 4.2.1, are defined by a horizontal axis with a scale of calendar years and a vertical axis with a scale describing the expected range of magnitudes of the index in question. Annual performance indices shall be plotted on these charts and a series of tests may then be performed to assess the stability of annual performance, shifts in performance and longer-term performance trends.

Control charts for each of the following indices shall be developed and utilized to monitor Availability Measures for each Voltage Class within each PTO's system:

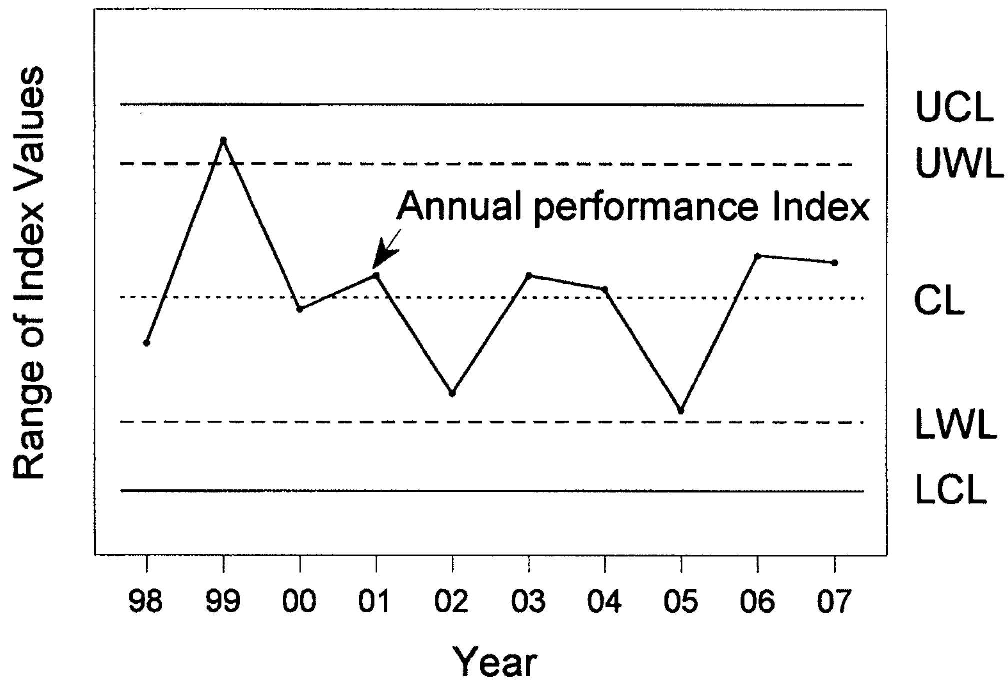

Figure 4.2.1 Sample Control Chart

- Index 1: Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits.
- Index 2: Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS).
- Index 3: Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS).

The control charts incorporate a center control line (CL), upper and lower control limits (UCL and LCL, respectively), and upper and lower warning limits (UWL and LWL, respectively). The CL represents the average annual historical performance for a period prior to the current calendar year. The UCL and LCL define a range of expected performance extending above and below the CL. For the annual proportion of Transmission Line Circuits with no Forced Outages$^{(IMS)}$, the limits are based on standard control chart techniques for binomial proportion data. For the other two indices, bootstrap resampling techniques are used to determine empirical UCL and LCL at 99.75% and 0.25% percentile values, respectively, for means from the historical data. The bootstrap procedure is described in Section 4.2.2 of this Appendix C. Similarly, the UWL and LWL define a range of performance intending to cover the percentiles from 2.5% to 97.5%. The bootstrap algorithm is also used to determine these values. Thus, the UCL and LCL will contain about 99.5% of resampling means from the Voltage Class of interest. UWL and LWL will contain about 95% of the resampling means. These limits coincide with the usual choices for control charts when the means are approximately normal. Bootstrap estimation procedures are used here since the sampling means do not follow the normal distribution model. The bootstrap estimation procedures ensure consistent control chart limits by using a starting base number ("seed") for its random number generator. Accuracy or reduced variances in the control chart limits are attained by using the average control chart limits generated from applying ten repetitions or cycles of the bootstrap sampling method. Collectively, the CL, UCL, LCL, UWL and LWL provide reference values for use in evaluating performance as described in Section 4.2.3 of this Appendix C.

For the special case where there is a Voltage Class with only one Transmission Line Circuit, individual and moving range control charts should be used for Index 1 and 2. The method used herein for calculating Index 3 is not applicable for those Voltage Classes containing less than six Transmission Line Circuits. The Maintenance Procedures will be used by the PTOs to calculate Index 1, 2, or 3 where the methods provided herein do not apply. More information on the individual and moving range control charts can be found in the user manuals of the statistical software recommended by the TMCC and approved by the ISO Governing Board for use in creating the control charts.

4.2.1. CALCULATIONS OF ANNUAL AVAILABILITY MEASURES INDICES FOR INDIVIDUAL VOLTAGE CLASSES

Separate annual Availability Measures indices shall be calculated for each Voltage Class and each PTO as described below by utilizing the calculations discussed in Section 4.1 of this Appendix C.

Annual Average Forced Outage$^{(IMS)}$ Frequency for All Transmission Line Circuits (Index 1):

$$F_{vc,k} = \frac{1}{N_k} \sum_{i=1}^{N_k} f_{ik}$$

where

$F_{vc,k}$ = frequency index for the Voltage Class, vc, (units = Forced Outages$^{(IMS)}$ /Transmission Line Circuit). The frequency index equals the average (mean) number of Forced Outages$^{(IMS)}$ for all Transmission Line Circuits within a Voltage Class for the calendar year "k".

N_k = number of Transmission Line Circuits in Voltage Class in calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

f_{ik} = frequency of Forced Outages$^{(IMS)}$ for the "i^{th}" Transmission Line Circuit as calculated in accordance with Section 4.1.1 of this Appendix C for calendar year "k".

Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for those Transmission Line Circuits with Forced Outages$^{(IMS)}$ (Index 2):

$$D_{vc,k} = \frac{1}{N_{o,k}} \sum_{i=1}^{N_{o,k}} d_{ik}$$

where

$D_{vc,k}$ = duration index for the Voltage Class (units = minutes/Transmission Line Circuit). The duration index equals the average accumulated duration of

Forced Outages$^{(IMS)}$ for all Transmission Line Circuits within a Voltage Class which experienced Forced Outages$^{(IMS)}$ during the calendar year "k".

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ for the "ith " Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) greater than zero for calendar year "k" as calculated in accordance with Section 4.1.1 of this Appendix C.

<u>Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$ (Index 3):</u>

$$P_{vc,k} = \frac{N_k - N_{o,k}}{N_k}$$

where

$P_{vc,k}$ = index for the proportion of Transmission Line Circuits for the Voltage Class with no Forced Outages$^{(IMS)}$ for the calendar year "k".

N_k = number of Transmission Line Circuits in Voltage Class for calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

4.2.2. DEVELOPMENT OF LIMITS FOR CONTROL CHARTS

The CL, UCL, LCL, UWL and LWL for the three control charts (Annual Average Forced Outage$^{(IMS)}$ Frequency for All Transmission Line Circuits; Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for those Transmission Line Circuits with Forced Outages$^{(IMS)}$; and Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$) on which the annual Availability Measures indices are to be plotted shall be calculated as described below. The CL, UCL, LCL, UWL and LWL for each of the three control charts shall be determined using continuously recorded Forced Outage$^{(IMS)}$ data for the ten calendar year period immediately preceding the date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

In the event that a PTO does not have reliable, continuously recorded Forced Outage$^{(IMS)}$ data for this 10 calendar year period, that PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, that PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO within 90 days after the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

The ISO shall periodically review the control chart limits and recommend appropriate modifications to each PTO in accordance with this Appendix C.

4.2.2.1. CENTER CONTROL LINES (CLs)

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability Measures indices described in Section 4.2.1 of this Appendix C except that the time period is expanded from a single calendar year to ten calendar years, unless a shorter period is justified by a PTO, for the period preceding the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement. To account for this change, a count of Transmission Line Circuit years is included in the equations as shown below to enable derivation of CLs which represent average performance during a multi-year period.

CL for Annual Average Transmission Line Circuit Forced Outage(IMS) Frequency

$$CL_{fvc} = \sum_{k=1}^{Y} \sum_{i=1}^{N_k} f_{ik} \, / \, (\sum_{k=1}^{Y} N_k)$$

where

CL_{fvc} = center control line value for the Forced Outage(IMS) frequencies for each of the Transmission Line Circuits in the Voltage Class for "*Y*" calendar years prior to the date a TO becomes a PTO.

Y = number of calendar years prior to the date a TO becomes a PTO for which the PTO has reliable, continuously recorded Forced Outage(IMS) data. *Y*=10 is preferred.

CL for Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS)

$$CL_{dvc} = \sum_{k=1}^{Y} \sum_{i=1}^{N_{o,k}} d_{ik} \, / \, (\sum_{k=1}^{Y} N_{o,k})$$

where

CL_{dvc} = center control line value for accumulated Forced Outage(IMS) duration for each of the Transmission Line Circuits in the Voltage Class for "*Y*" calendar years prior to the date a TO becomes a PTO in which the Forced Outage(IMS) frequency (f_{ik}) was greater than zero.

CL for Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)

$$CL_{Pvc} = \frac{\sum_{k=1}^{Y} (N_k - N_{o,k})}{\sum_{k=1}^{Y} N_k}$$

where

CL_{Pvc} = center control line value for the proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages$^{(IMS)}$ for "*Y*" calendar years prior to the date a TO becomes a PTO.

4.2.2.2. UCLs, LCLs, UWLs AND LWLs

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for Voltage Classes Containing Four or More Transmission Line Circuits with Forced Outages$^{(IMS)}$ for Five or More Calendar Years

The UCLs, UWLs, LWLs, and LCLs for the control charts for each Voltage Class containing four or more Transmission Line Circuits with Forced Outages$^{(IMS)}$ shall be determined by bootstrap resampling methods as follows: The available historical data for Index 1 and 2 will each be entered into columns. A "seed" is then selected prior to beginning the sampling process. The ISO assigns a number for the "seed" prior to each calendar year's development of the control charts. The "seed" allows the user to start the sampling in the same place and get the same results provided the data order hasn't changed. For Index 1, sampling with replacement will occur for the median number of Transmission Line Circuits per calendar year in a Voltage Class for the time period being evaluated. A sample, the size of which is the median number of all Transmission Line Circuits for the period being evaluated, is taken from the column of actual frequency values for all Transmission Line Circuits. A mean is calculated from this sample and the resulting number will be stored in a separate column. This process will be repeated 10,000 times in order to create a column of sampling means from the historical database. The column of sampling means is then ordered from the smallest to largest means. From this column percentiles are determined for a UCL (99.75), a LCL (0.25), a UWL (97.5), and a LWL (2.5). Thus, for one cycle, the limits are determined by resampling from the historical database, calculating statistics of interest, in this case means, and then estimating appropriate limits from the resampling means. Ten cycles of this same process are necessary to get ten values each of UCLs, LCLs, UWLs, and LWLs. The average for the ten values of each limit is taken to provide the UCL, LCL, UWL, and LWL values used in analyzing annual performance. The procedure is repeated for Index 2, forming means for the median number of

Transmission Line Circuits with Forced Outages$^{(IMS)}$ in this Voltage Class for the time period being evaluated. See **Bootstrapping - A Nonparametric Approach to Statistical Inference** (1993) by Christopher Z. Mooney and Robert D. Duval, Sage Publications with ISBN 0-8039-5381-X, and **An Introduction to the Bootstrap** (1993) by Bradley Efron and Robert J. Tibshirani, Chapman and Hall Publishing with ISBN 0-412-04231-2 for further information.

Consider an example to illustrate how the bootstrap procedure works for one cycle of the ten required. Assume that a Voltage Class has approximately 20 Transmission Line Circuits per calendar year with a history of ten calendar years. Furthermore, assume that about 15 Transmission Line Circuits per calendar year experience Forced Outages$^{(IMS)}$. Therefore, there are 10 x 15 = 150 Forced Outage$^{(IMS)}$ durations available for bootstrap sampling. Place these 150 Forced Outage$^{(IMS)}$ durations in a column, say "outdur," in a specified order. The order is automatically provided in the bootstrap algorithm developed by the ISO and made available to the PTO. The bootstrap algorithm will sample 15 rows from "outdur" with replacement. That is, any row may, by chance, be sampled more than once. From these 15 values determine the sample mean and place this in another column, say "boot". Repeat this sampling process 10,000 times adding the new means to "boot". The column "boot" now has 10,000 means from samples of size 15 from the original Forced Outage$^{(IMS)}$ duration data for this Voltage Class. The next step is to locate the appropriate percentiles from these means for use in determining the control chart limits for one cycle. This is accomplished by ordering the column "boot" from smallest-to-largest mean and restoring these ordered means in "boot". The percentiles which are needed are 99.75% (UCL), 97.50% (UWL), 2.50% (LWL) and 0.25% (LCL). These are easily estimated from the sorted means by finding the associated rows in the column "boot". For example, LWL will be estimated as the average of the 250th and 251st rows in column "boot". Likewise the other limits will be determined. Of course, the CL is the actual mean average for 15 Transmission Line Circuits over the ten calendar years using the formulas in Section 4.2.2.1 of this Appendix C. This example is for one cycle. Nine more cycles of this process will establish the more accurate control and warning limits necessary to evaluate a PTO's annual performance.

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for All Other Voltage Classes

When data for less than four Transmission Line Circuits with Forced Outages$^{(IMS)}$ are available per calendar year in a Voltage Class for fewer than five calendar years, an exhaustive enumeration of all possible selections with replacement may need to be performed. This is because the number of possible samples for bootstrap resampling will be less than the aforementioned 10,000 resampling frequency used for Voltage Classes containing four or more Transmission Line Circuits with Forced Outages$^{(IMS)}$ for five or more calendar years. For example, if a Voltage Class has only two Transmission Line Circuits per calendar year for five calendar years, the data base will consist of 2*5 = 10 accumulated Forced Outage$^{(IMS)}$ durations assuming both Transmission Line Circuits experience one Forced Outage$^{(IMS)}$ or more per calendar year. Resampling two values from the column of ten yields only 10**2 = 100 possible means. Thus, bootstrap resampling of 10,000 would over-sample the original data 10,000/100 = 100 times.

For the general case, let M = the number of accumulated Forced Outage$^{(IMS)}$ durations (or Forced Outage$^{(IMS)}$ frequencies) from the historical database. If n is the median number of Transmission Line Circuits per calendar year, there are M**n = U possible enumerated means for this Voltage Class. The procedure to determine the appropriate limits for a Voltage Class is to order the column containing "U" enumerated means from smallest to largest means. Then, the UCL, LCL, UWL, and LWL are determined from this vector as described above (i.e., at the 99.75, 0.25, 97.5, and 2.5 percentiles, respectively).

UCLs, LCLs, UWLs and LWLs for Index 3 When Number of Transmission Line Circuits is > 125

According to standard procedures for proportion control charts for Voltage Classes where the median number of Transmission Line Circuits in service is greater than 125 for any given calendar year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the "kth" calendar year are determined using the normal approximation to the binomial distribution. The formulas are:

$$UCL = CL_{Pvc} + 3S_{Pvc,k} \qquad LCL = CL_{Pvc} - 3S_{Pvc,k}$$

UWL and LWL are calculated by replacing the "3" above with "2".

and

$$S_{Pvc,k} = \sqrt{CL_{Pvc}(1 - CL_{Pvc})/N_k}$$

where

$S_{Pvc,k}$ = standard deviation for the annual proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages$^{(IMS)}$ for each "kth" year of the "*Y*" calendar years prior to the date a TO becomes a PTO. If LCL or LWL is less than zero, they should be set to zero by default.

UCLs, LCLs, UWLs and LWLs for Index 3 when Number of Transmission Line Circuits is less than or equal to 125 and greater than or equal to six

The UCLs, LCLs, UWLs, and LWLs for the control charts for each Voltage Class shall be based on exact binomial probabilities for those Voltage Classes having equal to or more than six, but less than or equal to 125 median Transmission Line Circuits per calendar year. A customized macro and a statistical software package approved by the ISO creates the proportion control charts. The macro determines the control limits and use of the exact binomial or the normal approximation to the binomial for computing the control chart limits. This macro ensures the UCL and LCL contain about 99.5% and the

UWL and LWL contain about 95% of the binomial distribution. The percentile values of the UCL, UWL, LWL, and LCL are respectively 99.75%, 97.5%, 2.5%, and 0.25%.

The UCL, UWL, LWL, and LCL are calculated using the following formulas:

$$\mathbf{UCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{UWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{LWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{LCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

Where

P_1 = A cumulative binomial probability that if not equal to the P_2 value is representing the percentile value that is less than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_1 = 0.99529 and is closest to the 99.75 percentile value, from the low side, P_1 = 0.99529 should be used in the UCL formula).

P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas (e.g., P_2 = 0.9975 in the UCL formula and = 0.025 in the LWL formula).

P_3 = A cumulative binomial probability that if not equal to the P_2 value is representing the percentile value that is greater than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_3 = 0.99796 and is closest to the 99.75 percentile value, from the high side, then P_3 = 0.99796 should be used in the UCL formula).

X_1 = The number of Transmission Line Circuits with no Forced Outages$^{(IMS)}$ associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_1 = 0.99529 and represents the closest percentile from below the 99.75 percentile for the case where 19 Transmission Line Circuits had no Forced Outages$^{(IMS)}$, then X_1 = 19 should be used in the UCL formula).

n = The median number of Transmission Line Circuits that are in service in a given calendar year. This number remains the same in each of the UCL, UWL, LWL, and LCL formulas.

4.2.3. EVALUATION OF AVAILABILITY MEASURES PERFORMANCE

The control charts shall be reviewed annually by the ISO and PTOs in order to evaluate Availability Measures performance. The annual evaluation shall consist of an examination of each of the control charts to determine if one or more of the following four tests indicate a change in performance. The four tests have been selected to enable identification of exceptional performance in an individual calendar year, shifts in longer-term performance, and trends in longer-term performance.

Tests

- **Test 1:** The index value for the current calendar year falls outside the UCL or LCL.
- **Test 2:** At least v1 consecutive annual index values fall above the CL or v2 consecutive annual index values fall below the CL. The actual values of v1 and v2 will be output from the bootstrap resampling procedures. The choices for v1 and v2 are designed to keep the probability of these events less than one percent.

Table 1. Values of v1 and v2 for Percentiles of the CL in Specified Ranges

Percentile	v1	v2
35 - 39	10	5
40	10	6
41 - 43	9	6
44 - 46	8	6
47 - 48	8	7
49 - 51	7	7
52 - 53	7	8
54 - 56	6	8
57 - 59	6	9
60	6	10
61 - 65	5	10

Thus, for example, if for a particular Voltage Class the percentile of the historical CL is 55%, this Table indicates that the CL is located at the 55 percentile of all bootstrap means in the "boot" column. From Table 1, v1=6, and v2=8.

- **Test 3:** At least two out of three consecutive annual index values fall outside the UWL or LWL on the same side of the CL.
- **Test 4:** Six or more values are consecutively increasing or consecutively decreasing.

Therefore, Test 1 is designed to detect a short-term change or jump in the average level. Tests 2 and 4 are looking for long-term changes. Test 2 will detect a shift up in averages or a shift to a lower level. Test 4 is designed to detect either a trend of continuous increase in the average values or continuous decrease. Test 3 is designed to assess changes in performance during an intermediate period of three calendar years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three calendar year period. Together the four tests allow the ISO to monitor the Availability performance of a Voltage Class for a PTO.

If none of these tests indicate that a change has occurred, performance shall be considered to be stable and consistent with past performance. If one or more of these tests indicates a change then Availability performance shall be considered as having improved or degraded relative to the performance defined by the control chart. Table 4.2.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last calendar year's Availability performance indices did not trigger any of the four tests. If none of the four tests are triggered, the new limits will be constructed including the last calendar year's data.

The control chart limits may be modified each year to reflect the number of Transmission Line Circuits in service during that calendar year if necessary. However, it is suggested that unless the number of Transmission Line Circuits changes by more than 30% from the previous calendar year, the use of the median number of Transmission Line Circuits should continue. Consider an example; suppose after the control chart has been prepared for a Voltage Class, next calendar year's data arrives with the number of Transmission Line Circuits 30% higher than the median used in the past. New limits will be generated in order to assess the Availability performance for that calendar year.

For the special case where only one Transmission Line Circuit has a Forced Outage(IMS) in a Voltage Class during a calendar year, the assessment process for Index 2 is as follows; if Index 2 for this Transmission Line Circuit does not trigger any of the four tests, no further action is necessary. If, however, one or more of the tests are triggered, then limits for this Transmission Line Circuit for that calendar year should be recalculated based on the historical data for this Transmission Line Circuit alone using an individual and moving range control chart. The only test warranted here is Test 1. More information on the individual and moving range control charts can be found in the user manuals of the statistical software used in creating the control charts

Table 4.2.1 Performance Indications Provided by Control Chart Tests

Control Chart Type	Test Number	Test Results	Performance Status Indicated by Test Results: Improvement	Performance Status Indicated by Test Results: Degradation
Annual Average Forced Outage(IMS) Frequency	1	value is above the UCL		X
		value is below the LCL when LCL>0	X	
	2	v1 or more consecutive values above the CL		X
		v2 or more consecutive values below the CL	X	
	3	2 out of 3 values above the UWL		X
		2 out of 3 values below the LWL	X	
	4	6 consecutive values increasing		X
		6 consecutive values decreasing	X	
Annual Average Accumulated Forced Outage(IMS) Duration	1	value is above the UCL		X
		value is below the LCL when LCL>0	X	
	2	v1 or more consecutive values above the CL		X
		v2 or more consecutive values below the CL	X	
	3	2 out of 3 values above the UWL		X
		2 out of 3 values below the LWL	X	
	4	6 consecutive values increasing		X
		6 consecutive values decreasing	X	
Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)	1	value is above the UCL	X	
		value is below the LCL when LCL>0		X
	2	v1 or more consecutive values above the CL	X	
		v2 or more consecutive values below the CL		X
	3	2 out of 3 values above the UWL	X	
		2 out of 3 values below the LWL		X
	4	6 consecutively increasing values	X	
		6 consecutively decreasing values		X

4.3. AVAILABILITY REPORTING

Each PTO shall submit an annual report to the ISO within 90 days after the end of each calendar year describing its Availability Measures performance. This annual report shall be based on Forced Outage$^{(IMS)}$ records. All Forced Outage$^{(IMS)}$ records shall be submitted by each PTO to the ISO and shall include the date, start time, end time, affected Transmission Facility, and the probable cause(s) if known.

5. MAINTENANCE PRACTICES

5.1. INTRODUCTION

These ISO Transmission Maintenance Standards, as they may be periodically revised in accordance with the provisions of the Transmission Control Agreement and this Appendix C, and as they may be clarified by the Maintenance Procedures, shall be followed by each PTO in preparing, submitting, and amending its Maintenance Practices. The Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including facility importance.

5.2. PREPARATION OF MAINTENANCE PRACTICES

5.2.1. TRANSMISSION LINE CIRCUIT MAINTENANCE

As may be appropriate for the specific Transmission Line Circuits under the ISO's Operational Control, each PTO's Maintenance Practices shall describe the Maintenance activities for the various attributes listed below:

5.2.1.1. OVERHEAD TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Conductor and shield wire
- Disconnects/pole-top switches
- Structure grounds
- Guys/anchors
- Insulators
- Rights-of-way

- Structures/Foundations
- Vegetation Management

5.2.1.2. UNDERGROUND TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Cable/Cable systems
- Cathodic Protection
- Fluid pumping facilities
- Terminations
- Arrestors
- Rights-of-way
- Splices
- Structures/vaults/manholes
- Vegetation Management

5.2.2. STATION MAINTENANCE

As may be appropriate for the specific Stations under the ISO's Operational Control, each PTO's Maintenance Practices shall describe Maintenance activities for the various attributes listed below:

- Inspections, scheduled and unscheduled
- Battery systems
- Circuit breakers
- Direct Current transmission components
- Disconnect switches
- Perimeter fences and gates
- Station grounds
- Insulators/bushings/arrestors
- Reactive power components
- Protective relay systems
- Station Service equipment
- Structures/Foundations
- Transformers/regulators
- Vegetation Management

5.2.3. DESCRIPTIONS OF MAINTENANCE PRACTICES

Each PTO's Maintenance Practices shall include a schedule for any time-based Maintenance activities and a description of conditions that will initiate any performance-based activities. The Maintenance Practices shall describe the Maintenance methods for each substantial type of component and shall provide any checklists/report forms, which may be required for the activity. Where appropriate, the Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility. Where appropriate, the Maintenance Practices shall specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the Transmission Facility.

5.3. REVIEW AND ADOPTION OF MAINTENANCE PRACTICES

5.3.1. INITIAL ADOPTION OF MAINTENANCE PRACTICES

In conjunction with its application to become a PTO, each prospective PTO shall provide to the ISO its proposed Maintenance Practices which comply with the requirements set forth in this Appendix C and Section 14.1 of the Transmission Control Agreement. This information shall provide sufficient detail for the ISO to assess the proposed Maintenance Practices.

The ISO shall review the proposed Maintenance Practices and may provide recommendations for an amendment. To the extent there is any disagreement between the ISO and the prospective PTO regarding the prospective PTO's proposed Maintenance Practices, such disagreement shall be resolved by the ISO and prospective PTO so that the ISO and the prospective PTO will have adopted Maintenance Practices, consistent with the requirements of this Appendix C and the Transmission Control Agreement, for the prospective PTO at the time that the ISO assumes Operational Control of the prospective PTO's Transmission Facilities. To the extent there are no recommendations, the proposed Maintenance Practices will be adopted by the ISO and the prospective PTO as the Maintenance Practices for that prospective PTO.

5.3.2. AMENDMENTS TO THE MAINTENANCE PRACTICES

5.3.2.1. AMENDMENTS PROPOSED BY THE ISO

Each PTO shall have in place Maintenance Practices that have been adopted by the ISO as set forth in this Appendix C. The ISO shall periodically review each PTO's Maintenance Practices having regard to these ISO Transmission Maintenance Standards and Maintenance Procedures. Following such a review, the ISO may recommend an amendment to any PTO's Maintenance Practices by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The PTO may draft amended language in response to the ISO's recommendation. If the PTO exercises its option to draft amended language to the ISO's proposed amendment, the PTO shall so notify the ISO within 30 days after the receipt of notice from the ISO. The PTO will provide the ISO with its proposed amendment language in a time frame mutually agreed upon between the PTO and the ISO. If, after the ISO receives the proposed amendment language from the PTO, the ISO and the PTO are unable to agree on the language implementing the ISO recommendation, then the provisions of Section 5.3.3.2 of this Appendix C shall apply.

5.3.2.2. AMENDMENTS PROPOSED BY A PTO

Each PTO may provide to the ISO its own recommendation for an amendment to its own Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement.

5.3.3. DISPOSITION OF RECOMMENDATIONS

5.3.3.1. If the ISO makes a recommendation to amend the Maintenance Practices of a PTO, as contemplated in Section 5.3.2.1 of this Appendix C, that PTO shall have 30 Business Days to provide a notice to the ISO, pursuant to

Section 26.1 of the Transmission Control Agreement, stating that it does not agree with the recommended amendment or that it intends to draft the language implementing the amendment, as set forth in Section 5.3.2.1 of this Appendix C. If the PTO does not provide such a notice, the amendment recommended by the ISO shall be deemed adopted.

If a PTO makes a recommendation to amend its own Maintenance Practices, as contemplated in Section 5.3.2.2 of this Appendix C, the ISO shall have 30 Business Days to provide a notice to that PTO, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not concur with the recommended amendment. If the ISO does not provide such a notice, then the recommended amendment shall be deemed adopted. Notwithstanding the foregoing, if an amendment proposed by a PTO to its own Maintenance Practices meets the objectives of Section 2.1 of this Appendix C and is submitted in accordance with the requirements in Section 5.2 of this Appendix C, the ISO shall adopt said amendment.

If any amendment to a PTO's Maintenance Practices is adopted, the PTO will specify the transition time to implement the adopted amendment so as to ensure the ISO and PTO are clear as to the implementation time frame where Maintenance may be performed under both sets of practices.

5.3.3.2. If the ISO or a PTO makes a recommendation to amend Maintenance Practices and if the ISO or PTO provides notice within the 30 Business Days specified in Section 5.3.3.1 of this Appendix C that the ISO or PTO does not agree with the recommended amendment, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If, after such efforts, the PTO and the ISO cannot reach a resolution, the pre-existing Maintenance Practices shall remain in effect. Either Party may, however, seek further redress through appropriate processes, including non-binding discussions at the TMCC and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. The PTO may also request, during the initial attempts at resolution and at any stage of the redress processes, a deferral of the ISO recommended amendment and the ISO shall not unreasonably withhold its consent to such a request. Following the conclusion of any and all redress processes, the PTO's Maintenance Practices, as modified, if at all, by these processes, shall be deemed adopted by the ISO, as the Maintenance Practices for that PTO, pursuant to the implementation time frame agreed to between the PTO and the ISO.

5.3.3.3. If the ISO determines, that prompt action is required to avoid a substantial risk to reliability of the ISO Controlled Grid, it may direct a PTO to implement certain temporary Maintenance activities in a period of less than 30 Business Days, by issuing an advisory to the PTO to that effect, by way of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. Any advisory issued pursuant to this Section 5.3.3.3 shall specify why implementation solely under Sections 5.3.3.1 and 5.3.3.2 of this Appendix C is not sufficient to avoid a substantial risk to reliability of the ISO Controlled Grid, including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. The ISO shall consult with the relevant PTO before issuing a Maintenance advisory. Upon receiving such an advisory, a PTO shall implement the temporary Maintenance activities in question, as of the date specified by the ISO in its advisory, unless the PTO provides a notice to the ISO, in accordance with Section 26.1 of the Transmission Control Agreement, that the PTO is unable to implement the temporary Maintenance activities as specified. Even if the PTO provides such a notice, the PTO shall use its best efforts to implement the temporary Maintenance activities as fully as possible. All Maintenance advisories shall cease to have effect 90 Business Days after issuance by the ISO or on such earlier date as the ISO provides in its notice. Any Maintenance advisories required to remain in effect beyond 90 Business Days shall require a recommendation process pursuant to Section 5.3.3.1 or Section 5.3.3.2 of this Appendix C.

5.4. QUALIFICATIONS OF PERSONNEL

All Maintenance of Transmission Facilities shall be performed by persons who, by reason of training, experience and instruction, are qualified to perform the task.

6. MAINTENANCE RECORD KEEPING AND REPORTING

A PTO shall maintain and provide to the ISO records of its Maintenance activities in accordance with this Section 6 of this Appendix C.

6.1. PTO MAINTENANCE RECORD KEEPING

The minimum record retention period for Transmission Facilities subject to time based scheduled intervals shall be the designated Maintenance cycle plus two years. The minimum record retention period for all other Transmission Facility Maintenance activities identified through inspection, assessment, diagnostic or another process shall be a minimum of 2 years after the date completed.

A PTO's Maintenance records shall, at a minimum, include the: 1) responsible person; 2) Maintenance date; 3) Transmission Facility; 4) findings (if any); 5) priority rating (if any); and 6) description of Maintenance activity performed.

6.2. PTO MAINTENANCE REPORTING

Each PTO will submit a Standardized Maintenance Report as outlined in the Maintenance Procedures. The ISO will accept, at the PTO's option, a Standardized Maintenance Report in either electronic or paper form.

If a PTO retains records in a manner that includes additional information, such records may be submitted in that manner.

Each PTO shall provide to the ISO Maintenance records as described in Section 6.1 and as set forth in the Maintenance Procedures.

6.3. ISO VISIT TO PTO'S TRANSMISSION FACILITIES

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement to determine if the Maintenance Practices are being followed by a PTO.

7. ISO AND TRANSMISSION MAINTENANCE COORDINATION COMMITTEE

The ISO shall establish and convene a Transmission Maintenance Coordination Committee (TMCC). The TMCC shall develop and, if necessary, revise the Maintenance Procedures, including conveying information to and seeking input from PTOs and other interested stakeholders regarding these Maintenance Procedures and any proposed amendments or revision thereto. The TMCC will also make recommendations on the ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will convey information to and seek input from the PTOs and other interested stakeholders on these ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will also perform any other functions assigned in this Appendix C.

Although the role of the Transmission Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members.

8. REVISION OF ISO TRANSMISSION MAINTENANCE STANDARDS AND MAINTENANCE PROCEDURES

8.1 REVISIONS TO ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO, PTOs, or any interested stakeholder may submit proposals to amend or revise these ISO Transmission Maintenance Standards. All proposals shall be initially submitted to the TMCC for review in accordance with this Appendix C. Any revisions to these ISO Transmission Maintenance Standards shall be made only upon recommendation by the TMCC and only in accordance with the provisions and requirements of the Transmission Control Agreement and this Appendix C.

8.2 REVISIONS TO AND DEVIATIONS FROM MAINTENANCE PROCEDURES

The ISO or any PTO may submit proposals to the TMCC to amend or revise the Maintenance Procedures. Any deviations from the Maintenance Procedures should be held to a minimum and will be negotiated between the ISO and the affected PTO.

9. INCENTIVES AND PENALTIES

9.1 DEVELOPMENT OF A FORMAL PROGRAM

The TMCC shall periodically investigate and report to the ISO on the appropriateness of a formal program of incentives and penalties associated with Availability Measures. Should the TMCC ever recommend that the ISO adopt a formal program of incentive and penalties, the formal program will only be adopted as set forth in Section 9.2 of this Appendix C.

9.2 ADOPTION OF A FORMAL PROGRAM

Any formal program of incentives and penalties adopted by the ISO in connection with matters covered in Section 14 of the Transmission Control Agreement or this Appendix C, shall be established only: 1) with respect to Availability Measures; 2) upon recommendation of the TMCC as set forth in Section 9.1 of this Appendix C; 3) by express incorporation into this Appendix C in accordance with the provisions of the Transmission Control Agreement; and 4) upon approval by the FERC. Nothing in this Appendix C shall be construed as waiving or limiting in any way the right of any party or PTO to oppose or protest any formal program of incentives and penalties filed, proposed or adopted by the ISO and/or FERC or any portion thereof.

9.3 IMPOSITION OF PENALTIES IN THE ABSENCE OF A FORMAL PROGRAM

In the absence of a formal program of incentives and penalties, the ISO may seek FERC permission for the imposition of specific penalties on a PTO on a case-by-case basis in the event that the relevant PTO 1) exhibits significant degradation trends in Availability performance due to Maintenance, or 2) is grossly or willfully negligent with regard to Maintenance.

9.4 NO WAIVER

Nothing in this Appendix C shall be construed as waiving the rights of any PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC, the approval by FERC of any specific penalty or sanction, or the specific imposition by the ISO of any FERC approved penalty or sanction on the PTO.

9.5 LIMITATIONS ON APPLICABILITY TO NEW PTOS

For a new PTO, the Availability Measures system needs to be used and updated during a five calendar year phase in period, as set forth in Section 4.2 of this Appendix C, to be considered in connection with any formal program of incentives and penalties associated with Availability Measures.

10. COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain and the ISO shall operate Transmission Facilities in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable laws and regulations.

10.1 SAFETY

Each PTO shall take proper care to ensure the safety of personnel and the public in performing Maintenance duties. The ISO shall operate Transmission Facilities in a manner compatible with the priority of safety. In the event there is conflict between safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. DISPUTE RESOLUTION

Any dispute between the ISO and a PTO relating to matters covered in this Appendix C shall be subject to the provisions of the Transmission Control Agreement, including the dispute resolution provisions set forth therein.

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SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

Revised as of October 10, 2006

I. OVERVIEW

The preferred source of electrical power for the San Onofre Nuclear Generating Station (SONGS) electrical loads (safety-related and non-safety-related) is the ***offsite power supply*** or 230 kV grid. The offsite power supply is sometimes referred to as the ***preferred power supply*** in the applicable regulatory documents.

The offsite power supply is considered "Operable" with respect to the SONGS Operating License and Technical Specifications when it can provide sufficient capacity and capability to supply electrical loads needed to safely shut down the reactor and mitigate certain specified accident scenarios.

The offsite power supply is considered "Inoperable" with respect to the SONGS Operating License and Technical Specifications if it is degraded to the point that it cannot provide sufficient capacity and capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS.

It is a necessary condition of the SONGS Operating License and Technical Specifications that the offsite power supply be Operable at all times. If the offsite power supply is declared Inoperable, action must be taken to shut down an online SONGS unit(s) and, for an offline unit, to suspend activities as required by the SONGS Operating License and Technical Specifications.

The level of degradation that would result in inoperability can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable to safely shutdown the units or to supply emergency electrical loads.

Since accident scenarios for which the SONGS plant is designed can result in a unit trip, it is imperative that this trip not impair the operability of the offsite power supply. If both SONGS units are online and one unit trips (due to an accident or otherwise), the non-tripped unit will provide local voltage support to the SONGS switchyard, and 230 kV system voltage will remain within the required range. In cases where one SONGS unit is online and one unit offline, the offsite power supply must be sufficiently robust to survive a trip of the online unit and meet the SONGS voltage requirements in the post-trip condition. A dual unit trip is not the limiting condition since a plant accident is not postulated simultaneous with a dual unit trip. System Operating

Procedures (see Reference 9 below) and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and communicated to the SONGS Control Room.

The SONGS switchyard is made up of the Southern California Edison Company (SCE) switchyard and the San Diego Gas & Electric Company (SDG&E) switchyard. Unless specifically stated otherwise, SONGS switchyard requirements contained in this document apply to both the SCE switchyard and the SDG&E switchyard.

II. REQUIREMENTS

Note: **This section identifies the operational requirements for the SONGS offsite power supply. These requirements are part of the SONGS design basis and licensing basis. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating SONGS unit(s) to shutdown. Failure to meet these requirements must be communicated to SCE and the SONGS Control Room for operability determination as soon as practicable, but in any case, within one hour. Changes in the operation of the transmission network that conflict with these requirements must have prior approval by SCE.**

Note: **Specific requirements, procedures, operating bulletins, division orders, and analysis that support or provide the basis for the specific operational requirements may be revised periodically subject to prior approval of the affected parties.**

1. Nine transmission lines into the SONGS switchyard are normally in service. Any increase or decrease in the number of lines into the SONGS switchyard requires prior approval of SCE. (Reference 7 below)

   No line may be removed from service for greater than 30 days without prior notification to SCE. At least two independent transmission lines (one from SCE and one from SDG&E) between the transmission network (grid) and SONGS switchyard shall be in service at all times. (References 1, 2, 3, 4, 7, 8 below)

2. With both San Onofre units off-line, the SONGS offsite power source shall be capable of providing 158 MW and 96 MVAR to SONGS for normal operation and for shutting down the units during plant Design Basis Accident (DBA) conditions. (References 9, 10 below)

3. The minimum grid voltage at the SONGS switchyard shall be maintained at or above 218 kV. In the event of a system disturbance that can cause the voltage to dip below 218 kV, including the trip of a SONGS unit, the grid voltage shall

recover to 218 kV or above within 2.5 seconds. (References 9, 10, 12, 13, 18 below)

4. The following initiating events shall not result in the loss of grid stability or availability:

    a. The loss of a SONGS Unit (with the other unit already offline), or

    b. The loss of any generating unit on the SCE and SDG&E grids, or

    c. The loss of any major transmission circuit or intertie on the SCE and SDG&E grids, or

    d. The loss of any large load or block of load (e.g., due to a bus section outage) on the SCE and SDG&E grids. (References 2, 3, 4, 8 below)

5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below 234 kV. (References 10, 11, 18 below)

6. The normal operating voltage of the SONGS switchyard shall be maintained at 229 kV. The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. (References 10, 11, 18 below)

7. The 3 limiting conditions for SONGS offsite power supply operability are defined as follows:

    1. One SONGS unit is off- line, and

    2. One of the critical line (s) outages, in GCC Operating Procedure, OP-13: SONGS Voltage (reference 19) occurs, and

    3. VAR flows north and south of SONGS are above the threshold levels for the existing combined SCE and SDG&E import level as defined by the nomograms referenced in the GCC Operating Procedure, OP-13: SONGS Voltage.

Based on these nomograms and SONGS offline unit's status, whenever limiting conditions 1 and 2, as set forth in this Requirement 7, occur, the ISO (or the SCE Grid Control Center (SCE GCC), as directed by the ISO) shall, as soon as practicable but, in any case, within one hour of the event, perform an evaluation of system conditions to determine whether or not the SONGS offsite power supply remains Operable as defined herein. If the SONGS offsite power supply is Inoperable or cannot be determined to be Operable as defined herein, the ISO (or the SCE GCC, as directed by the ISO) shall notify the SONGS Control Room immediately of entry into the event. Subsequent to notification, the SONGS Control Room shall declare the offsite power supply Inoperable (in anticipation of losing the second SONGS unit) and shall declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected. The time period shall be within 1 to 24 hours, based on the SONGS plant and equipment conditions.

In order to ensure the continued ability to meet the 3 limiting conditions identified above in this Requirement 7, the following six requirements (a-f) must be met:

a. Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions that could render the offsite power supply Inoperable.

b. Procedures and programs shall be in effect to ensure that the SONGS Control Room is notified as soon as practicable but, in any case, within one hour of an event that renders the offsite power supply Inoperable.

c. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, shall render the offsite power supply Inoperable.

d. Auditable records of current system studies shall be made available to SCE as needed to demonstrate compliance with regulatory requirements. Study results, including revisions and updates, shall be formally transmitted to SCE.

e. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be formally transmitted to Vice President Nuclear Engineering and Technical Services, San Onofre Nuclear Generating Station. (References 1, 2, 19, and 21 below)

f. System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the Western Electricity Coordinating Council (WECC). (Reference 7 below)

8. In the event of loss of the SONGS offsite power:

__Note:__ **SONGS 2 and 3 are required by NRC regulations to be able to safely cope with a loss of all AC power (Station Blackout) for a maximum of four hours. The four hour coping duration is based on the expectation that at least one source of AC power (offsite transmission line or onsite diesel generator) will be restored to the blacked-out unit within the four hours to ensure the proper functioning of systems required for plant safety.**

a. Highest possible priority shall be given to restoring power to the SONGS switchyard. Procedures and training should consider several potential methods of transmitting power from black-start capable units to the SONGS switchyard. This includes such items as nearby gas turbine generators, portable generators, hydro generators, and black-start fossil power plants. (References 15, 26, 28 below)

b. Should incoming lines to the SONGS switchyard be damaged, highest priority shall be assigned to repair and restoration of at least one line into the SONGS switchyard.

c. Repair crews engaging in power restoration activities for SONGS shall be given the highest priority for manpower, equipment, and materials.

d. Formal programs and procedures shall be in place to effect items a, b and c above. (References 14, 15, 16, 17, 26, 27 below)

9. Grid frequency shall be maintained at 60 Hertz (nominal). A trip of one SONGS unit shall not cause the grid frequency to dip below 59.7 Hertz. SCE and SDG&E shall comply with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan. (References 7, 20 below)

10. SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS Updated Final Safety Analysis Report (UFSAR) shall be maintained. It is recognized that the SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report may be revised from time to time. In the event the reliability criteria are revised, a system assessment and/or study (as described under specification 7) shall be performed to determine if the revised reliability criteria adversely impact grid reliability and availability as defined in this specification. Results of the assessment and/or study together with a copy of the revised reliability criteria shall be provided to SCE. Changes in grid operation based on the revised criteria and associated studies shall not be implemented without prior approval of SCE. (Reference 7 below)

11. Patrol and inspection of SCE and SDG&E transmission lines, to ensure that the physical and electrical integrity of transmission components are maintained, shall be performed as required by the SONGS UFSAR or in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent. (Reference 7 below)

12. Line insulators on lines which carry power from the plant to the grid shall be washed as required by the SONGS UFSAR or on an appropriate wash cycle in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent. The purpose and frequency of which is proven to prevent line outages that may result from flashovers due to accumulated contamination. (Reference 7 below)

13. Maintenance, testing and calibration of SCE and SDG&E station equipment and protective relays shall be performed as required by the SONGS UFSAR or in accordance with the current ISO approved Electrical Station Maintenance Practice, whichever requirement is more stringent. (Reference 7 below)

14. Preventive maintenance and testing of SONGS switchyard batteries shall be performed in accordance with IEEE 450-1985 or IEEE 450-2002 subsequent to SONGS converting its battery maintenance program to IEEE 450-2002 requirements. (Reference 7, 23 below)

15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS UFSAR shall be provided annually to facilitate periodic updates to the UFSAR by SONGS that are required by 10CFR50.71(e).

III REFERENCES (Current approved revision except as noted)

1) SONGS 2&3 Operating License and Technical Specifications, Section 3.8, Electrical Power Systems

2) 10CFR50 Appendix A, General Design Criterion 17 (GDC-17), Electrical Power Systems

3) NUREG 75/087, Standard Review Plan Revision 1, Section 8.2, Offsite Power System

4) NUREG 0800, Standard Review Plan Revision 2, Section 8.2, Offsite Power System

5) NUREG 0800, Standard Review Plan Revision 2, Branch Technical Position ICSB-11 (PSB), Stability of Offsite Power Systems

6) NUREG 0712, SONGS 2&3 Safety Evaluation Report, Section 8.0, Electric Power Systems

7) SONGS 2 & 3 Updated Final Safety Analysis Report, Section 8.0, Electric Power

8) ANSI/IEEE Std. 765-2002 Preferred Power Supply for Nuclear Power Generating Stations

9) SONGS Design Calculation E4C-082, System Dynamic Voltages During Design Basis Accident

10) SONGS Design Calculation E4C-090, Auxiliary System Voltage Regulation

11) SONGS Design Calculation E4C-092, Short Circuit Studies

12) SONGS Design Calculation E4C-098, 4 kV Swgr Protective Relay Setting

13) DBD-SO23-120, SONGS Design Basis Document, 6.9KV, 4.16KV and 480V Electrical Systems

14) 90051, SONGS Station Blackout Analyses

15) NUMARC 87-00 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors

16) Letter from M. 0. Medford (SCE) to the Document Control Desk (NRC), dated April 17, 1989, Subject: "Response to 10 CFR 50.63, `Loss of all Alternating Current Power,' San Onofre Nuclear Generating Station Units 1, 2 and 3"

17) Letter from F. R. Nandy (SCE) to the Document Control Desk (NRC), dated May 1, 1990, Subject: "Supplemental Response to 10 CFR 50.63, 'Loss of All Alternating Current Power,' Station Blackout (TAC No. 68599/600), San Onofre Nuclear Generating Station Units 1, 2, and 3"

18) System Operating Bulletin 17 Appendix, System Voltage Control for San Onofre Nuclear Generating Station

19) GCC Operating Procedure, OP-013: SONGS Voltage

20) System Operating Bulletin 113, San Onofre 220 kV System Separation

21) Regulatory Guide 1.93, Revision 0, Availability of Electric Power Sources

23) SCE Division Order 60.20, Storage Batteries

26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration

27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV

28) SDG&E Control Procedure 1150, Capacity & Energy Emergencies - SDG&E System Emergencies

29) IEEE Std, 450-1985 IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations

30) IEEE Std. 450-2002 IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications

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NOTICES

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ATTACHMENT B

TRANSMISSION CONTROL AGREEMENT

BLACKLINE REVISIONS

August 11, 2006

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* * *

<u>4.4.4 **Trans Bay Cable**</u>

<u>4.4.4.1 In addition to the foregoing, the ISO, Trans Bay Cable LLC ("Trans Bay Cable"), and the Participating TOs acknowledge and agree that, following</u>

the ISO's approval of Trans Bay Cable's application for Participating TO status and upon the effective date of Trans Bay Cable's TO Tariff as approved by FERC, Trans Bay Cable shall be entitled and obligated to recover the just and reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has Entitlements through Trans Bay Cable's Transmission Revenue Requirement as established from time to time by FERC, including the specific rate principles approved by FERC in Docket No. ER05-985, to the extent that the transmission assets and associated facilities used to provide the Entitlements, as well as the Entitlements themselves, are placed under ISO Operational Control.

4.4.4.2 In reliance on the continued availability of a FERC-approved Transmission Revenue Requirement, as set forth above, Trans Bay Cable will not withdraw from this Agreement except in connection with the transfer, sale or disposition of any of its Entitlements in compliance with Sections 3.3, 4.4, and any other applicable provision of this Agreement.

4.4.4.3 If Trans Bay Cable should seek to transfer, sell or dispose of its Entitlements or any part thereof, then in addition to any and all other obligations imposed on such a transfer, sale or disposition by this Agreement, any applicable provisions of the ISO Tariff, and FERC rules and regulations, Trans Bay Cable shall require as a condition of such transfer, sale or disposition that the transferee of any of its Entitlement(s): (a) assume in writing Trans Bay Cable's rights and obligations under this Agreement, including without limitation all of the obligations imposed by this Section 4.4.4, *e.g.*, the obligation to recover the just and reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has Entitlements, as set forth in Section 4.4.4.1, exclusively through a FERC-approved Transmission Revenue Requirement; (b) become a Participating TO in the ISO; and (c) assume the obligation to bind each and every one of its transferees, successors and assigns to all of the obligations assumed by Trans Bay Cable under this Agreement. For the avoidance of doubt, the transfer of any of Trans Bay Cable's Entitlements cannot take place unless and until the holder of any such Entitlements has, in conjunction with the transfer, become a Participating TO in the ISO.

4.4.4.4 For the avoidance of doubt, the Parties hereby also confirm that the Operating Memorandum dated May 16, 2005, between Trans Bay Cable, the City of Pittsburg, California, and Pittsburg Power Company and filed by Trans Bay Cable in Docket No. ER05-985, including the option agreement contained therein, does not address or pertain to any transfer, disposition, sale or purchase of any of Trans Bay Cable's Entitlements.

4.4.4.5 Nothing in this Section 4.4.4 shall be interpreted as affecting the right of any party to seek to increase or decrease, at the FERC or appeals therefrom, the established or proposed Transmission Revenue Requirement of Trans Bay Cable or any subsequent holder of any of the Entitlements.

4.4.4.6 Notwithstanding the foregoing subsections of Section 4.4.4, this Section 4.4.4 shall become null and void in the event of and upon the first to occur of: (a) Trans Bay Cable receives for three (3) consecutive months either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff, or a pro rata reduction in payments under

Section 11.16.1 of the ISO Tariff, with each such underpayment or pro rata reduction equal to or greater than twenty percent (20%) of the monthly amount due and owing to Trans Bay Cable from the ISO, or (b) Trans Bay Cable receives either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff which, when calculated on a cumulative annual basis, is equal to or greater than five percent (5%) of the total amount due and owing to Trans Bay Cable from the ISO for the twelve (12) month period ending prior to the month or months in which such underpayment or pro rata reduction occurs, *provided* such an underpayment or pro rata reduction does not result from: (i) Access Charge sales fluctuations that impact the monthly Access Charge revenue disbursement to Trans Bay Cable, but which are subject to annual TRBAA true-ups to be made by the Participating TO pursuant to Section 6.1 of Schedule 3 of Appendix F of the ISO Tariff; (ii) Trans Bay Cable's action or failure to act; (iii) an error that has been corrected by the ISO; or (iv) a billing or payment dispute between Trans Bay Cable and the ISO.

4.4.4.7 Should this Section 4.4.4 become null and void under Section 4.4.4.6, then Trans Bay Cable, the ISO and the other Participating TOs shall remain bound by all of the remaining provisions of this Agreement.

* * *

~~8.3 Non-ISO Controlled Grid Critical Protective Systems.~~

~~Each Participating TO may alter the settings and functionality of protective relay systems and Remedial Action Schemes that have not been designated as ISO Controlled Grid Critical Protective Systems without the consent of the ISO, provided that~~

~~such changes do not reduce the normal or emergency rating of a facility identified in the ISO Register. If the facility rating will be reduced, the Participating TO shall obtain approval of the ISO prior to making such changes. In addition, the Participating TO shall promptly report to the ISO any facility rating increases that result from any changes to its protective relay settings or Remedial Action Schemes.~~

* * *

10.5 Interconnection Responsibilities of Western.

Notwithstanding any other provision of this Section 10, the responsibilities of Western to allow interconnection to its Path 15 Upgrade facilities and Entitlements set forth in Appendix A (Western) shall be as set forth in Western's General Requirements for Interconnection as those requirements are set forth in Western's TO Tariff or in Western's "Open Access Transmission Tariff" ("OATT"), as applicable. Western shall be subject to the provisions of this Section 10 to the extent they are not inconsistent with the provisions of Western's TO Tariff or OATT, as applicable. Execution of this Agreement shall not constitute agreement of any Party that Western is in compliance with FERC's regulations governing interconnections.

* * *

14.1. ISO Determination of Standards.

The ISO has adopted and shall ~~adopt~~maintain, in consultation with the Participating TOs through the Transmission Maintenance Coordination Committee, and in accordance with the requirements of this Agreement, the standards for the maintenance, inspection, repair, and replacement of transmission facilities under its

Operational Control in accordance with Appendix C. These standards, ~~which~~ as set forth in Appendix C, are and shall be performance-based or prescriptive or both, ~~will~~ and provide for high quality, safe, and reliable service and shall take into account costs, local geography and weather, the Applicable Reliability Criteria, national electric industry practice, sound engineering judgment and experience.

~~14.2. Existing Standards.~~

~~Until such time as the ISO adopts standards pursuant to Section 14.1, the ISO shall measure the performance of Participating TOs in relation to the maintenance, inspection, repair and replacement of transmission facilities by their existing standards. Each Participating TO shall provide the ISO with such information as the ISO shall require to identify such Participating TO's existing maintenance standards and measure its performance against the relevant standards.~~

14.~~3~~2. Availability ~~Formula~~.

14.~~3~~2.1 **Availability Measure**. The ISO performance-based standards shall be based on the availability measures described in ~~Section 4 of~~ Appendix C of this Agreement.

14.~~3~~2.2 **Excluded Events**. Scheduled Approved Maintenance Outages and certain Forced Outages will be excluded pursuant to ~~Section 4.2.3 of~~ Appendix C of this Agreement from the calculation of the availability measure.

14.~~3~~2.3 **Availability Measure Target**. The ~~Maintenance Coordination Committee~~ ISO and each Participating TO shall jointly develop for the Participating TOs an availability measure target, which may be defined by a range. The target will be based on prior Participating TO performance and developed in accordance with ~~Section~~

~~4 of~~ Appendix C of this Agreement~~ and national benchmarks~~.

14.~~3~~2.4 **Calculation of Availability Measure**. The availability measure shall be calculated annually by the Participating TO and reported to the ISO for evaluation of the Participating TO's compliance with the availability measure target. This calculation will be determined ~~the availability measure~~ in accordance with ~~Section 4 of~~ Appendix C of this Agreement.

14.~~3~~2.5 **Compliance with Availability Measure Target**. The ISO and the Participating TO may track the availability measure on a more frequent basis (e.g., quarterly, monthly), but the annual calculation shall be the sole basis for determining the Participating TO's compliance with its availability measure target.

14.~~3~~2.6 **Public Record**. The Participating TO's annual availability measure calculation ~~and the associated availability measure~~with its summary data shall be made available to the public.

14.~~4.~~3. Revisions~~ to Standards~~.

The ISO and Participating TOs shall periodically review ~~with the Participating TOs the standards and incentives implemented pursuant to this Section 14 and~~Appendix C, through the Transmission Maintenance Coordination Committee process, ~~shall modify these standards~~ and ~~incentives~~in accordance with the provisions of Appendix C and this Agreement shall modify Appendix C as necessary.

14.~~5.~~4. Incentives and Penalties.

The ISO ~~shall~~may, subject to regulatory approval, and as set forth in Appendix C, develop ~~incentive~~ programs which reward or impose sanctions on Participating TOs by reference to their availability measure and the extent to which the

~~4 of~~ Appendix C of this Agreement~~ and national benchmarks~~.

14.~~3~~2.4 **Calculation of Availability Measure**. The availability measure shall be calculated annually by the Participating TO and reported to the ISO for evaluation of the Participating TO's compliance with the availability measure target. This calculation will be determined ~~the availability measure~~ in accordance with ~~Section 4 of~~ Appendix C of this Agreement.

14.~~3~~2.5 **Compliance with Availability Measure Target**. The ISO and the Participating TO may track the availability measure on a more frequent basis (e.g., quarterly, monthly), but the annual calculation shall be the sole basis for determining the Participating TO's compliance with its availability measure target.

14.~~3~~2.6 **Public Record**. The Participating TO's annual availability measure calculation ~~and the associated availability measure~~with its summary data shall be made available to the public.

14.~~4.~~3. Revisions~~ to Standards~~.

The ISO and Participating TOs shall periodically review ~~with the Participating TOs the standards and incentives implemented pursuant to this Section 14 and~~Appendix C, through the Transmission Maintenance Coordination Committee process, ~~shall modify these standards~~ and ~~incentives~~in accordance with the provisions of Appendix C and this Agreement shall modify Appendix C as necessary.

14.~~5.~~4. Incentives and Penalties.

The ISO ~~shall~~may, subject to regulatory approval, and as set forth in Appendix C, develop ~~incentive~~ programs which reward or impose sanctions on Participating TOs by reference to their availability measure and the extent to which the availability performance imposes demonstrable costs or results in demonstrable benefits ~~for~~ to Market Participants.

* * *

17.2. Participating TO Records and Information Sharing.

17.2.1 **Existing Maintenance Standards**. Each Participating TO shall provide to the ISO, as set forth in ~~a format and at the time to be established by the ISO in coordination with the Participating TO,~~ Appendix C hereto: (1) the Participating TO's standards for inspection, maintenance, repair, and replacement of its facilities under the ISO's Operational Control ~~in effect as of the date it executes this Agreement~~; and (2) information, notices, or reports regarding the Participating TO's compliance with the inspection, maintenance, repair, and replacement standards set forth in Appendix C hereto.

17.2.2 **Other Records**. Each Participating TO shall provide to the ISO and maintain current data, records, and drawings describing the physical and electrical properties of the facilities under the ISO's Operational Control ~~and shall maintain records of all inspections, maintenance, replacement, and repairs performed on such facilities~~, which records shall be shared with the ISO under reasonable guidelines and procedures to be specified by the ISO.

17.2.3 **Required Reports**. Pursuant to this Agreement and the provisions of the ISO Tariff, each Participating TO shall provide to the ISO timely information, notices, or reports regarding matters of mutual concern, including:

i. System Emergencies, Forced Outages and other incidents affecting the ISO Controlled Grid;

ii. Maintenance Outage requests, including yearly forecasts required by Section 2.3.3.5 of the ISO Tariff; and

iii. System Planning Studies, including studies prepared in connection with Interconnections or any transmission facility enhancement or expansion~~; and~~.

~~iv. Compliance with the inspection, maintenance, repair, and replacement standards established under Section 14.~~

17.2.4 **Other Reports**. The ISO may, in accordance with the provisions of this Agreement and Appendices hereto, upon reasonable notice to the Participating TO, request that the Participating TO provide the ISO with such information or reports as are necessary for the operation of the ISO Controlled Grid. The Participating TO shall make all such information or reports available to the ISO in the manner and time prescribed by this Agreement or Appendices hereto or, if no specific requirements are so prescribed, within a reasonable time and in a form to be specified by the ISO.

* * *

17.5. Review of Information and Record-Related Policies.

The ISO shall periodically review the requirements of this Section 17 ~~annually~~ and shall, consistent with reliability and regulatory needs, other provisions of this Agreement, and Appendices hereto, seek to standardize reasonable record keeping, reporting, and information sharing requirements.

APPENDIX A2

List of Entitlements Being Placed Under ISO Operational Control

(Includes only those where PG&E is a service rights-holder)

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Pacific Power & Light, SCE, SDG&E	Transmission Use Agreement –PP&L Rate Schedule with FERC	Transmission	Upon 40 years beginning approx. 1968	
~~2.~~	~~SCE, SDG&E~~	~~California Power Pool – PG&E Rate Schedule FERC No. 27~~	~~Power Pool~~	~~Terminated~~	~~5/6/97~~
2~~3~~.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement – PG&E Rate Schedule FERC No. 38	Transmission	~~4~~8/1/2007	Both entitlement and encumbrance.
3~~4~~.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan – PG&E Rate Schedule FERC No. 183	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classified~~y~~ as an entitlement since loop flow is reduced or an encumbrance if PG&E is asked to cut.
4~~5~~.	TANC and other COTP Participants, and WAPA	Owners Coordinated Operations Agreement – PG&E Rate Schedule FERC No. ~~146~~229	~~Interconnection, s~~ Transmission system coordination, curtailment sharing, rights allocation, scheduling~~,~~ ~~transmission~~	1/1/2043, or on two years' notice, or earlier if other agreements terminate	Both entitlement and encumbrance~~.~~
~~6.~~	~~WAPA~~	~~EHV Transmission Agreement – Contract No. 2947A – PG&E Rate Schedule FERC No. 35~~	~~Transmission~~	~~1/1/2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.~~	~~Both entitlement and encumbrance.~~
5~~7~~.	Various – See Attachment A	Western Systems Power Pool Agreement – WSPP Rate Schedule FERC No. 1	Power Sales, transmission	Upon WSPP expiration	Both entitlement and encumbrance.
6~~8~~.	Vernon (City of)	Transmission Service Exchange Agreement – PG&E Rate Schedule FERC No. 148	Transmission	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for service on COTP

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
1.	California Companies Pacific Intertie Agreement (CCPIA)	PG&E, -SDG&E	40	July 31, 2007	• 43% of the California Companies entitlements on the Pacific Intertie.
2.	City-Edison Pacific Intertie D-C Transmission Facilities Agreement	LADWP	448~~303~~	3/31/2041~~2040~~ -or sooner by mutual agreement of the parties.	• Edison owns 50% of -the D-C transmission facility. (Per CCPIA, this ownership is part of the California Companies entitlements on the Pacific Intertie).
3.	PP&L Agreement	PP&L, PG&E, SDG&E		2008	• California Companies are entitled to use the entire capacity on the PP&L 500 kV transmission line from Malin to Indian Spring for the term of the agreement. Per CCPIA Edison is entitled to 43% of the capacity available on the Pacific Intertie.
~~4.~~	~~WAPA Contract with California Companies for Extra High Voltage Transmission and Exchange Service~~	~~WAPA, PG&E, SDG&E~~	~~37~~	~~January 1, 2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.~~	• ~~WAPA owns a 500 kV transmission line from Malin to Round Mountain. WAPA receives 400 MW of Tracy-Round Mountain transmission service. The capacity on Malin-Round Mountain not used by WAPA is available to CCPIA Parties.~~
~~5~~4.	Los Angeles-Edison Exchange Agreement	LADWP	219	May 31, 2025	• 500 MW of bi-directional firm entitlement on the PDCI transmission line.
~~6.~~	~~Coordinated Operations Agreement~~	~~PG&E, SDG&E, and COTP Participants~~	~~270.7~~	~~January 1, 2043~~	• ~~The allocation of Available Scheduling Capability between COTP parties and PACI parties is calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.~~
5.	Owners Coordinated Operations Agreement	PG&E, SCE, SDG&E, WAPA & COTP		SCE's participation terminates on 7/31/07 with CCPIA termination unless as otherwise contemplated by Section 6.3.1 of the Agreement.	• Provides for the continued coordinated operation of the PACI and COTP. The allocation of Available Scheduling Capability between the parties is calculated as specified in the Agreement.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~7~~6.	Pasadena-Edison 230-KV Interconnection and Transmission Agreement	Pasadena	55	~~2011~~8/4/2010	• Goodrich-Gould and Goodrich-Laguna Bell 230 kV transmission line interconnect Edison's system with Pasadena's system at Pasadena's Goodrich Substation. Lines have been re-configured from arrangement shown in contract. • Edison maintains and operates Goodrich 230 kV Substation.
~~8.~~	~~[Terminated – Not Available]~~				
~~9~~7.	Victorville-Lugo Interconnection Agreement	LADWP	51	2019 or sooner by mutual agreement	• 1950 MW towards Edison, 900 MW towards LADWP. Transfer capability of the interconnection is established through joint technical studies.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~10~~8.	City-Edison Sylmar Interconnection Agreement	LADWP	307	On 5 years notice by either party any time after the termination of the City-Edison Pacific Intertie DC Transmission Facilities Agreement.	• Sylmar-Pardee #1&2, Sylmar-Gould and Sylmar-Eagle Rock 230 kV transmission line interconnections at Sylmar including circuit breakers and busses. Lines have been re-configured from arrangement described in contract. • Edison owns one of the two regulating transformers at Sylmar.
~~11~~9.	City-Edison Owens Valley Interconnection and interchange Agreement	LADWP	50	On 12 months notice by either party.	• At the request of either party and by mutual agreement, LADWP's and Edison's respective systems interconnected ~~-~~at LADWP's ~~-~~Haiwee 34.5 kV Substation, may be operated in parallel, which normally operates open at Haiwee.
~~12~~10.	City-Edison 400,000 kVA Interconnection Agreement (Velasco)	LADWP	215	On 3 year written notice by either party.	• Edison's portion of the normally open Laguna Bell-Velasco 230 kV transmission line from Laguna Bell to the point where ownership changes.
~~13~~11.	Edison-Los Angeles Inyo Interconnection Agreement	LADWP	306	On 5 year advance written notice by either party or by mutual agreement.	• Inyo 230/115 kV Substation, Inyo Phase Shifter, Control-Inyo 115 kV transmission line and 230 kV Tap to LADWP's Owens Gorge-Rinaldi 230 kV transmission line.
~~14~~12.	Edison-Los Angeles Sepulveda Canyon Power Plant Transmission Service Agreement	LADWP	280	Termination of Sepulveda Canyon Power Plant Interconnection Agreement or sooner by either party giving a one year notice. Should LADWP change rates, SCE has the right to terminate with 60 days written notice.	• 9 MW of transmission service from the high voltage leads of Sepulveda Canyon Power Plant to the 230 kV bus at Sylmar.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~15.~~	~~[Terminated a/o March 26, 2001 – Not Available]~~				
~~16~~1 3.	Amended and Restated IID-Edison Mirage 230 kV Interconnection Agreement	IID	314	On one year notice but not prior to the termination date of the IID-Edison Transmission Service Agreement for Alternate Resources.	• Edison's interconnection with IID at Mirage and the point of interconnection on the Devers – Coachella Valley line.
~~17~~1 4.	IID Edison Transmission Service Agreement for Alternative Resources	IID		Earlier of Dec 31, 2015, or the termination date of the last Plant Connection Agreement.	• Transmission Service on IID's 230 kV system to transmit -the output of QFs resources to Edison's system, via Mirage Substation.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~18~~15.	Four Corners Principles of Interconnected Operation	APS, SRP, EPE, PSNM, TGE	47.0	None	• Generation principles for emergency service. • Edison's facility at Four Corners includes its portion of the Eldorado – Moenkopi from Eldorado to CA/NV boarder of the Eldorado-Moenkopi – Four Corners 500 kV transmission line. • Edison can separate its wholly-owned facilities from parallel operation with others under abnormal operating conditions without prior notice. • Edison can separate its wholly-owned facilities from parallel operation with others for maintenance on reasonable advance notice (see Co-tenancy Agreement for facilities). • Edison has the right to schedule emergency service from each party.
~~19~~16.	Four Corners Project Co-Tenancy Agreement and Operating Agreement	APS, SRP, EPE, PSNM, TGE	47.2	2016	• Edison has co-tenancy ownership of 32% in the Four Corners 500 kV switchyard, 12% in the 345 kV switchyard and 48% in the 345/500 kV bus-tie transformer bank. • Edison has rights to sufficient capacity in the switchyards and bus-tie transformer bank to permit its entitlement to Four-Corners Project power and energy to be delivered to the point where the Eldorado-Moenkopi-Four Corners transmission line connects to the Four Corners 500 kV Switchyard. • Edison may use any unused capacity in the switchyard for any purpose, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership of the requesting co-owners.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~20~~17.	Navajo Interconnection Principles	USA, APS, SRP, NPC, LADWP, TGE	76	None	• Generation principles for emergency service.
~~21~~18	Edison – Navajo Transmission Agreement	USA, APS, SRP, NPC, LADWP, TGE	264	5/21/23	• In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency transmission service without a charge. The amount of service provided is proportional to each parties' entitlement to the~~-~~ total capability of the transmission system described above.
~~22~~19.	ANPP High Voltage Switchyard Agreement	APS, SRP, PSNM, EPE, SCPPA, LADWP	320	2031	• Edison has 21.77% undivided ownership interest as a tenant-in-common in the ANPP High Voltage Switchyard. • Edison has rights to transmit through the ANPP High Voltage Switchyard up to its 15.8% share of generation from ANPP, or a substitute equal amount, plus any other generation up to the extent of its transmission rights in the Palo Verde-Devers 500 kV Transmission Line • Edison has additional rights to use any unused capacity in the ANPP High Voltage Switchyard, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~23.~~	~~[See Eldorado System Conveyance and Cotenancy Agreement (Line No. 26)]~~				
~~24~~20.	Mutual Assistance Transmission Agreement	IID, APS, SDG&E	174	~~On~~In 2034 or sooner by mutual agreement of the parties.	• In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
~~25~~21.	Midway Interconnection	PG&E	309	July~~,~~ 31, 2007	• Edison's share of 500 kV Midway-Vincent transmission system: – Midway-Vincent #1 – Midway-Vincent #2 – Midway-Vincent #3 from Vincent Substation to mile 53, Tower 1
~~26~~22.	Amended and Restated Eldorado System Conveyance and Co-Tenancy	NPC, SRP, LADWP	424	July 1, 2006	• Edison's share of -Eldorado System Components: • Eldorado Substation: Edison Capacity Entitlement = Eldorado Substation Capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]; • Mohave Switchyard: Edison Capacity Entitlement = 884 MW; • Eldorado – Mohave 500 kV line: (Edison Capacity Entitlement – Eldorado – Mohave 500 kV line capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]); • Eldorado – Mead 230 kV Line Nos. 1 & 2: (Edison Capacity Entitlement = Eldorado – Mead 230 kV Line No. 1 &2 capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Capacity Entitlement [158 MW].

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
~~27.~~	~~Sierra Pacific – Edison Silver Peak 55 kV Interconnection Agreement~~	~~Sierra Pacific~~	~~310~~	~~2016 8/5/2016 or sooner on 90 days advance notice but not prior to the termination of Edison's Power Purchase Agree. From Chevron.~~	• ~~Control-Silver Peak A&C 55 kV transmission lines.~~ • ~~Edison's share of the Control-Silver Peak lines is from Control Substation to the CA/NV border.~~
~~28~~2 3.	WAPA-Edison 161 kV Blythe Substation Interconnection Agreement	WAPA	221	September 30, 2007 or sooner by 3 year advanced notice by either party.	• WAPA's Blythe 161 kV Substation, and Edison's Eagle Mountain-Blythe 161 kV transmission line. • Edison may transmit up to ~~72~~168 MW through WAPA's Blythe Substation, via the Eagle Mountain-Blythe 161 kV transmission line (Note: FP&L entitled to 96 MW of FTRs due to participation in facility upgrade project).
~~29~~2 4.	SONGS Ownership and Operating Agreements	SDG&E, Anaheim, Riverside	321	~~None.~~In effect until termination of easement for plant site.	• Edison's share of SONGS switchyard with termination of its 230 kV transmission lines: – SONGS – Santiago 1 and 2, – SONGS – Serrano, and – SONGS – Chino 230 kV
~~30~~2 5.	District-Edison 1987 Service and Interchange Agreement	MWD	~~203~~44 3	September 30, 2017 or on five years notice by either party.	• Transmission is owned by District, but is in ISO control area. If not in use by District, or the United States under existing contracts, District's Transmission Line is available to transmit any electric energy to which Edison may be entitled. • Up to 320 MW is required to supply District's Colorado River Aqueduct pump load. • District's Transmission Line is operated by the District as directed by Edison.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

~~31~~2 6.	Edison-Arizona Transmission Agreement	APS	282	~~On 2016~~2/28/2017 or later upon negotiation.	• Edison has ownership-like rights to the 500 kV Transmission line from the Four Corners Project to the Arizona-Nevada border. Edison also owns the 500 kV line from Arizona-Nevada border to Edison's Eldorado substation.
~~32~~2 7.	Mead Interconnection Agreement	WAPA	308	May 31, 2017	• Edison has rights to transmit its Hoover power • Edison's facilities include Eldorado-Mead 230 kV #1 and 2 transmission lines. • Edison may request additional firm transmission service rights through Mead Substation subject to availability as determined by WAPA.
~~33~~2 8.	Power Purchase Contract Between SCE and Midway-Sunset Cogeneration Company.	Midway-Sunset Cogeneration Company.		5/8/09	• 200 MW of capacity through Midway Substation.
~~31~~2 9.	Agreement for Mitigation of Major Loop Flow	Pacificorp, PG&E, SCE	Pacificorp R/S # 298	2/12/2020	• Pacificorp to operate Phase Shifting Transformers on the Sigurd-Glen Canyon and Pinto-Four Corners Transmission Lines in accord with contract.

APPENDIX A.2: SDG&E'S CONTRACT ENTITLEMENTS

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
66-020	California Companies Pacific Intertie Agreement	Edison, PG&E	20	Subject to FERC's approval and any litigation concerning term, no earlier than July 31, 2007.	7% of the California Companies entitlements on the Pacific Intertie, including delivery rights through SCE's system from Sylmar to SONGS (100 MW); and from SONGS to Sylmar (105 MW); from Midway to SONGS (161 MW); and from SONGS to Midway (109MW).
67-012	Pacific Power & Light Agreement	PP&L, PG&E, Edison		Subject to FERC's acceptance and any litigation concerning term, no earlier than 2008.	California Companies entitled to use the entire capacity on the PP&L 500 kV transmission line from Malin to Indian Spring for the term of the agreement. SDG&E is entitled to 7% of the capacity available on the Pacific Intertie.
~~67-100~~	~~WAPA contract with California Companies for Extra High Voltage Transmission and Exchange Service~~	~~WAPA, PG&E Edison~~	~~37~~	~~Subject to FERC's acceptance and any litigation concerning term, no earlier than January 1, 2005. May be extended at negotiated rates.~~	~~WAPA owns a 500 kV transmission line from Malin to Round Mountain. WAPA receives 400 MW of Tracy-Round Mountain transmission service. The capacity on Malin-Round Mountain not used by WAPA is available to California Companies Pacific Intertie parties.~~
~~92-000~~	~~Coordinated Operations Agreement~~	~~PG&E, Edison, and COTP participants~~	~~270.7~~	~~January 1, 2043.~~	~~The allocation of Available Scheduling Capability between COTP parties and the Companies Pacific Intertie parties calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.~~
	Owners Coordinated Operations Agreement	PG&E, Edison, and COTP participants		SDG&E's participation terminates on 7/31/07 with CCPIA termination unless as otherwise contemplated by Section 6.3.1 of the Agreement.	The allocation of Available Scheduling Capability between COTP parties and the Companies Pacific Intertie parties calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	Should a contingency occur in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None.	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey ~~Tap~~ (3 Lines) ~~- Mission~~ - Talega (2 lines) ~~- Encina~~

79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy.
78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by CFE of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031.	The parties are obligated to provide mutual switchyard assistance during emergencies to the extent possible. However, in the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E California Transmission System Participation Agreement	IID		June 24, 2051.	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500 kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E -- 85.64%; and IID -- 14.36%.
78-003	APS-SDG&E Arizona Transmission System Participation Agreement	APS		July 31, 2031.	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS -- 11%; SDG&E ~~--~~ ~~69~~76.22%; IID -~~-~~ ~~20~~12.78%.

APPENDIX A: CITY OF RIVERSIDE
TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	IPP-Adelanto Switching Station	Riverside-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	N-S 195 MW S-N 142 MW
2.	Marketplace Substation-Adelanto	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
3.	Westwing-Mead-Marketplace 500 kV	Riverside-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	12 MW
4.	Marketplace-McCullough 500 kV	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		31-Oct-30 31-Oct-30	118 MW 12 MW
5.	Adelanto-Victorville/Lugo	Riverside-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	118 MW
6.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Base Capacity Transmission Service Agreement		See Note 2	122 MW
7.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Additional Capacity Transmission Service Agreement		See Note 3	73 MW
8.	IPP-Mona Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	220 MW
	IPP-Gonder Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	31 MW
~~9.~~	~~Nevada-Oregon Border-Sylmar~~	~~Riverside-LADWP~~	~~Bi-directional~~	~~NOB/Sylmar 25 MW Firm Transmission Service Agreement (Seasonal: June – October)~~		~~31-Oct-04~~	~~25 MW~~
~~10~~9.	Nevada-Oregon Border-Sylmar	Riverside-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	23 MW
~~1~~10.	San Onofre-Vista	Riverside-SCE	To Vista	San Onofre Nuclear Generating Station Firm Transmission Service Agmt.		See Note 5	42 MW
11~~2~~.	Mead 230 kV-Vista	Riverside-SCE	To Vista	Hoover Firm Transmission Service Agreement		See Note 6	30 MW
12~~3~~.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Intermountain Power Project Firm Transmission Service Agreement		See Note 7	156 MW
13~~4~~.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Palo Verde Nuclear Generating Station Firm Transmission Service Agmt.		See Note 8	12 MW

Notes

1. Agreement terminates on: (i) removal of Mead-Adelanto Project from Service; or (ii) removal of Los Angeles-SCE interconnection at Victorville/Lugo.
2. Agreement terminates on: (i) June 15, 2027; or (ii) the date Riverside interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Riverside interconnects at Adelanto Switching Station; or (iii) 5-year's notice by LADWP.
4. Agreement terminates on: (i) termination of LADWP's rights to the Northern Transmission System; or (ii) termination of the IPP Additional Capacity Agreement.
5. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in San Onofre Nuclear Generating Station Units 2 and 3; or (iii) unacceptable FERC modification.
6. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in the Boulder Canyon Project (Hoover); or (iii) unacceptable FERC modification.
7. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in the Intermountain Power Project; or (iii) unacceptable FERC modification.
8. Agreement terminates on: (I) six months notice by Riverside; (ii) termination of Riverside's interest in the Palo Verde Nuclear Generating Station; or (iii) unacceptable FERC modification.

Appendix A
Trans Bay Cable, LLC
Transmission Entitlements

Trans Bay Cable Project Facilities

Trans Bay Cable LLC (TBC) will develop, finance and construct a high voltage, direct current transmission line of approximately fifty-five miles in length and associated facilities to establish a direct connection between Pacific Gas and Electric Company's (PG&E's) Pittsburg Substation located at a site adjacent to the City of Pittsburg, California in Contra Costa County to PG&E's Potrero Substation within the City of San Francisco (the Project). The transmission line will consist of an approximately 7,000-ton bundled cable consisting of a transmission cable, a fiber optic communications cable and a metallic return. The underwater portion of the transmission line will be laid by a ship or barge with special equipment in a single trench underneath San Francisco Bay. The remaining length of the transmission line (most likely a few hundred yards at either end of the line) will be buried underground, either through directional drilling or laid in a trench. In addition, the Project will involve the construction of two converter stations near each of the PG&E Substations to convert the alternating current received at the Pittsburg Substation to direct current and then back to alternating current at the Potrero Substation.

TBC will provide the funding for (i) the development and construction of the Project, (ii) the acquisition of all needed real property and other interests and (iii) the reimbursement of the on-going operation and maintenance expenses of the Project. In return and pursuant to the Operating Memorandum among TBC, the City of Pittsburg and Pittsburg Power Company which was accepted for filing by the Federal Energy Regulatory Commission (112 FERC ¶ 61,095, *order granting clarification,* 114 FERC ¶ 61,031), TBC will be granted 100% of the Entitlements to the transmission capacity created by the Project and all financial benefits associated with the Entitlements. In accordance with the TCA and the TO Tariff, TBC will transfer the Entitlements created by the Project to ISO Operational Control at the time the Project enters service.

PG&E APPENDIX B

List of Encumbrances on Lines and Facilities, and Entitlements Being Placed Under ISO Operational Control (per TCA Appendix A1 & A2)[1]

(Includes only those where PG&E is a service provider)

Abbreviations Used:

CDWR	=	California Department of Water Resources
SCE	=	Southern California Edison Company
SDG&E	=	San Diego Gas & Electric Company
SMUD	=	Sacramento Municipal Utility District
TANC	=	Transmission Agency of Northern California
WAPA	=	Western Area Power Administration

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Bay Area Rapid Transit	Service Agreement Nos. 42 and 43 to FERC Electric Tariff, First Revised Volume No. 12	Network Integration Transmission Service Agreement and Network Operating Agreement - OAT	10/1/2016	
2.	CDWR	Comprehensive Agreement – PG&E Rate Schedule FERC No. 77	Interconnection and Transmission	12/31/2014	Transmission Related Losses
3.	CDWR	Etiwanda Power Plant Generation Exchange – PG&E Rate Schedule FERC No. 169	Power exchanges	Evergreen, or on 5 years notice	
~~4.~~	~~CDWR~~	~~Extra High Voltage Transmission – PG&E Rate Schedule FERC No. 36~~	~~Transmission~~	~~1/1/2005~~	
~~5.~~4.	Dynegy Power Services	Control Area Transmission Agreement – PG&E Rate Schedule FERC No. 224	Transmission and various other services	Terminated 12/31/01. PG&E filing of FERC termination pending submittal ~~of a filing to FERC~~.	

[1] The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
~~6.~~5.	DOE Laboratories, WAPA	PG&E/WAPA/DOE-SF 10/30/98 Settlement Agreement – PG&E Rate Schedule FERC No. 147	Transmission Service	3/31/2009	
~~7.~~	~~Lawrence Livermore National Library, WAPA~~	~~PG&E/WAPA/DOE-SF Settlement Agreement – PG&E Rage Schedule FERC No. 147~~	~~Standby Transmission Service~~	~~3/31/2009~~	
~~8.~~6.	Midway-Sunset Co-Generation	Cogeneration Project Special Facilities – PG&E Rate Schedule FERC No. 182	Interconnection, transmission	1/1/2017	
~~9.~~7.	Minnesota Methane	Service Agreement No. 1, under FERC Electric Tariff, First Revised Volume No. 12	Firm Point-to-Point Transmission Service - OAT	10/1/2016	Effective 10/1/96
~~10.~~8.	Modesto Irrigation District	Interconnection Agreement – PG&E Rate Schedule FERC No. 116	Interconnection, transmission, power sales	4/1/2008	Power sales are coordination sales – voluntary spot sales
~~11.~~9.	NCPA, CSC, CDWR	Castle Rock-Lakeville CoTenancy Agreement – PG&E Rate Schedule FERC No. 139	Transmission facilities maintenance	Evergreen, or 1 year notice after 1/1/2015	
~~12.~~10.	Path 15 Operating Instructions Settlement, Revision 1 – Various, see FERC Docket No. ER04~~99-~~61~~1770-~~000~~1~~	Exhibit B-1 to this Appendix B to the TCA	Implements curtailment priorities consistent with various Existing Transmission Contracts. Establishes Path 15 Facilitator role for PG&E.	~~3/31/2003~~Upon request by PG&E after 1/1/05, subject to FERC acceptance.	
~~13.~~11.	Power Exchange	Control Area Transmission Service Agreement – PG&E Rate Schedule FERC No. 186	Transmission and various other services	Terminated 3/1/2000. PG&E filing of FERC termination pending submittal~~, or may extend if Destec does~~	

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
~~14.~~12.	Puget Sound Power & Light	Capacity and Energy Exchange – PG&E Rate Schedule FERC No. 140	Power exchanges	Terminates on 5 years' advance notice. ~~2007per 5 year advance notice received from Puget in 2002.~~	
~~15.~~13.	San Francisco (City and County of)	Interconnection Agreement - PG&E Rate Schedule FERC No. 114	Interconnection, transmission and supplemental power sales	7/1/2015	Power sales are Firm Partial Requirements
~~16.~~14.	Santa Clara (City of)	Mokelumne Settlement and Grizzly Development Agreement – PG&E Service Agreement No. 20 under FERC Electric Tariff Sixth Revised Volume No. 5	Transmission, power sales	1/1/2034	
~~17.~~15.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement – PG&E Rate Schedule FERC No. 38	Transmission service	~~7~~8/~~3~~1/2007	Both entitlement and encumbrance.
~~18.~~16.	SCE, Montana Power Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan – PG&E Rate Schedule FERC No. 221	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classified~~y~~ as an entitlement since loop flow is reduced or an encumbrance if PG&E is ~~we are~~ asked to cut.
~~19.~~17.	Shelter Cove	Interconnection Agreement – PG&E Rate Schedule FERC No. 198	Distribution	6/30/2006	Effective 8/15/96
~~20.~~18.	Sierra Pacific	Interconnection Agreement – PG&E Rate Schedule FERC No. 72	Interconnection and support services	Evergreen, or 3 years notice	
~~21.~~19.	SMUD	Interconnection Agreement – PG&E Rate Schedule FERC No. 136	Interconnection and transmission services	12/31/2009	
~~22.~~20.	SMUD	EHV Transmission Agreement – PG&E Rate Schedule FERC No. 37	Transmission	Terminated 1/1/2005 (appeal pending)	

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
~~23.~~21.	SMUD	Camp Far West Transmission Agreement – PG&E Rate Schedule FERC No. 91	Transmission	No notice of termination filed with FERC	
~~24.~~22.	SMUD	Slab Creek Transmission Agreement – PG&E Rate Schedule FERC No. 88	Transmission	No notice of termination filed with FERC	
~~25.~~23.	~~(~~TANC~~)~~ and other COTP Participants, and WAPA	Owners Coordinated Operations Agreement – PG&E Rate Schedule FERC No. 229~~146~~	Transmission system coordination, curtailment sharing, rights allocation, scheduling.	1/1/2043, or on two years' notice, or earlier if other agreements terminate	~~Establishes relationship of the COTP to the Control Area Operator~~Both entitlement and encumbrance
~~26.~~24.	~~(~~TANC~~)~~ and other COTP Participants	COTP Interconnection Rate Schedule – PG&E Rate Schedule FERC No. 144	Interconnection	Upon termination of COTP	
~~27.~~25.	TANC	Midway Transmission Service / South of Tesla Principles – PGE& Rate Schedule FERC No. 143	Transmission, curtailment priority mitigation,* replacement power	Same as the COTP Interim Participation Agreement, subject to exception	
~~28.~~26.	Turlock Irrigation District	Interconnection Agreement – PG&E Rate Schedule FERC No. 213	Interconnection, transmission~~,~~ ~~power sales~~	4/1/2008, subject to exception	~~Power Sales are Firm Obligation Sales (Partial Requirements); Contract Firm (Firm Sale requested by TID); and Coordination Sales – Voluntary Spot Sales~~

* Includes use of PG&E's DC Intertie or PDCI for prespecified mitigation of curtailments over Path 15.

~~29.~~27.	Vernon (City of)	Transmission Service Exchange Agreement – PG&E Rate Schedule FERC No. 148	Transmission service	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for Vernon's COTP rights
~~30.~~28.	WAPA	San Luis Unit – Contract No. 2207A – PG&E Rate Schedule FERC No. 227 (superseding Original Tariff Sheet Nos. 104 through 137 of PG&E Rate Schedule FERC No. 79)	Transmission	4/1/2016	
~~31.~~	~~WAPA, SCE & SDG&E~~	~~EHV Transmission Agreement – Contract 2947A – PG&E Rate Schedule FERC No. 35~~	~~Transmission rights, exchange and coordination and transmission service~~	~~1/1/2005, unless extended by agreement of the parties.~~	~~Both entitlement and encumbrance~~
~~32.~~	~~WAPA~~	~~Sale, Interchange and Transmission – Contract No. 2948A – PG&E Rate Schedule FERC No. 79~~	~~Integration, interconnection, transmission and power sales exchanges~~	~~1/1/2005~~	

Ref.#	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
~~33.~~	~~WAPA~~	~~Wintu Pumping Plant – Contract No. 2979A – PG&E Rate Schedule FERC No. 79~~	~~Transmission~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005~~	
~~34.~~	~~WAPA~~	~~Delta Pumping Plant – Contract No. DE-AC65-80WP59000 – PG&E Rate Schedule FERC No. 63~~	~~Transmission~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005, or 3 years notice~~	
~~35.~~	~~WAPA~~	~~Healdsburg, Lompoc & Ukiah – contract No. DE-MS65-83WP59055 –PG&E Rate Schedule FERC No. 81~~	~~Transmission~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005, or 4 years notice~~	
~~36.~~	~~WAPA~~	~~Sonoma County Water Agency – Contract No. 88-SAO-40002 – PG&E Rate Schedule FERC No. 126~~	~~Transmission~~	~~6/30/94, or concurrent with Contract No. 2948A expiration of 1/1/2005, or 4 years notice~~	
~~37.~~29.	WAPA	New Melones – Contract No. 8-07-20-P0004 – PG&E Rate Schedule FERC No. 60	Transmission	6/1/2032	Per WAPA, commercial operation date for New Melones was 6/1/82
~~38.~~	~~WAPA~~	~~Trinity County PUD & Lewiston Power Plant Contract No. 93-SAO-18008, Supplement No. 42 – PG&E Rate Schedule FERC No. 79~~	~~Transmission~~	~~1/1/2005~~	

Lien Mortgage

The lien of the First and Refunding Mortgage dated December 1, 1920 between PG&E and BNY Western Trust Company, as trustee, as amended and supplemented and in effect of the date hereof (the "PG&E Mortgage"). The transfer of Operation Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the PG&E Property which would be prior to the lien of the PG&E Mortgage; however, no consent of the trustee under the PG&E Mortgage is require to consummate the transfer of Operation Control to the ISO pursuant to this Agreement.

TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
1.	Devers - Mirage / Coachella 230 kV	IID	SCE to IID	Firm Transmission Service Agreement	268	On 3-year notice	100 MW May-October, 50 MW rest of the year.
~~2.~~	~~Devers - Banning ISO Grid Take Out Point serving Banning~~	~~Banning~~	~~Bi-dir~~	~~Pasadena Firm Transmission Service~~	~~382~~	~~Earlier of 12/31/03 or upon Banning's 1-year notice given after 1/1/02.~~	~~10 MW until 10/31/98, 5 MW beginning 1/1/99~~
~~3~~2.	Devers - ISO Grid Take Out Point serving Banning	Banning	To Banning	1995 San Juan Unit 3 Firm Transmission Service Agreement	381	Earlier of termination of Banning's interest in San Juan Unit 3 or Banning's 1-year notice given after 1/1/03	15 MW
~~4~~3.	Devers-- Vista	Colton	To Vista	1995 San Juan Unit 3 Firm Transmission Service Agreement	~~265~~365	Earlier of termination of Colton's interest in San Juan Unit 3 or Colton's 1-year notice given after 1/1/03	14.043 MW
~~5~~4.	Hinds - Vincent	MWD	Bi-dir.	District-Edison 1987 Service and Interchange Agreement	~~203~~443	The earlier of either (1) the term of MWD's Hoover Electric Service Contract (DE-MS65-86WP39583) expected to be 9/30/2017 or (2) five-year notice	110 MW
~~6.~~	~~Etiwanda - Vincent~~	~~MWD~~	~~to Vincent~~	~~Amended and Restated District Etiwanda Power Plant Transmission Service Agreement~~	~~292 First Revised~~	~~Earliest of termination MWD-PG&E Sale Contract, termination of PG&E-CDWR Exchange Contract, termination of SCE-CDWR Power Contract, termination of Interconnection Facilities Agreement, or April 1, 2014. As of the date of this document, this agreement is expected to terminate 12/31/04, which is the date the CDWR Power Contract is expected to terminate.~~	~~24 MW~~

Footnotes:

1. The following is an additional encumbrance that does not fit into the format for existing contract encumbrances. The additional encumbrance is: The lien of the Trust Indenture dated as of October 1, 1923, between Edison and Harris Trust and Savings Bank and Pacific-Southwest Trust & Savings Bank (D. G. Donovan, successor trustee), as trustees ("the Edison Indenture"). The transfer of control to the ISO pursuant to this Agreement (i) does not

require any consent from the trustees under the Edison Indenture, (ii) shall not be deemed to create any lien or charge on the Edison Transmission Assets that would be prior to the lien of the Edison Indenture, and (iii) shall not otherwise impair the lien of the Edison Indenture.

2. The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~7~~5.	Eldorado-Vincent	CDWR	Bi-dir.	~~Amended and Restated~~ Firm Transmission Service Agreement (Eldorado-Vincent)	113 ~~First Revised~~	Earlier of date that a) CDWR has obtained for replacement transmission service; b) CDWR is no longer entitled to Reid Gardner Unit 4 output; c) 12/31/2020; or, d) Reid Gardner Unit 4 is permanently retired from service.	235 MW
~~8~~6.	Eldorado / Mohave - Lugo	LADWP	Bi-dir.	Victorville - Lugo Interconnection Agreement	51	11/20/ 2019 or sooner by mutual agreement	Edison is required to provide capacity to LADWP equal to the product of LA's Capacity Share and the deemed capacity of the transmission system consisting of Mohave-Lugo, Mohave-Eldorado, Eldorado-Lugo, Eldorado-McCullough, McCullough-Victorville lines, and Victorville-Lugo 500 kV transmission lines.
~~9~~7.	Moenkopi - Eldorado	USA, APS, SRP, NPC, LADWP, TGE	Bi-dir.	Edison - Navajo Transmission Agreement	264	5/21/23	In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency service transmission rights without a charge.
~~10~~ 8.	Mohave – Eldorado	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425	7/1/06	If Mohave-Eldorado line is curtailed, pro-rata back up is provided on Mohave-Lugo and Eldorado-Lugo lines. If Mohave-Lugo is curtailed, pro-rata back-up is provided on Mohave-Eldorado. Amount of back up capacity is up to participant's Mohave Capacity Entitlement. For curtailment purposes, Capacity Entitlements are: Edison-884 MW; LADWP-316 MW; NPC-222 MW;SRP-158 MW.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~11~~ 9.	Eldorado - Mead	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425	7/1/06	If Eldorado-Mead lines are curtailed, line capacity is allocated pro rata in proportion to the following Capacity Entitlements: NPC-222 MW; SRP-158 MW; LADWP – 0 MW; Edison Capacity Entitlement is equal to entire capacity of the Eldorado-Mead Line Nos. 1&2 minus NPC Capacity Entitlement minus SRP Capacity Entitlement.
~~12~~ 10.	Mead - Mohave	NPC	To Mohave	Amended and Restated Agreement for Additional NPC Connection to Mohave Project	426	Co-terminous with Mohave Project Plant Site Conveyance and Co-Tenancy Agreement	Up to 222 MW of Back-up transmission service.
~~13~~ 11.	Mead - ISO Grid Take Out Point serving Banning	Banning	E-W	Hoover Firm Transmission Service Agreement	378	Earliest of: ~~agreement to terminate, or date in a~~ Banning's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	2 MW
~~14~~ 12.	Mead - Rio Hondo	Azusa	~~E-W~~Bi-dir	Sylmar Firm Transmission Service Agreement	375	Earliest of: ~~agreement to terminate, or~~ Azusa's 1-year notice given after 1/1/02, or termination of Azusa's interest in San Juan #3	8 MW
~~15~~ 13.	Mead - Rio Hondo	Azusa	E-W	Hoover Firm Transmission Service Agreement	372	Earliest of: ~~agreement to terminate, or date in an~~ Azusa's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	4 MW
~~16~~ 14.	Mead - Vista	Colton	E-W	Hoover Firm Transmission Service Agreement	361	Earliest of: ~~agreement to terminate, or date in a~~ Colton's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	3 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~17~~ 15.	Mead - Riverside	Riverside	E-W	Hoover Firm Transmission Service Agreement	~~389~~390	~~12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~180 day notice by Riverside or termination of WAPA Service Contract	30 MW
~~18~~ 16.	Mead - Laguna Bell	Vernon	Bi-dir	Mead Firm Transmission Service Agreement	207	~~Earlier of agreement to terminate~~Upon mutual agreement or termination of Hoover Power Sales Agreement	26 MW
~~19~~ 17.	Mead - Mountain Center	AEPCO	E-W	Firm Transmission Service Agreement	131	7/1/21 or on 10 years notice	10 MW
~~20~~ 18.	Palo Verde - Devers	LADWP	Bi-dir	Exchange Agreement	219	~~Earliest of construction of DPV#2, or removal of DPV1 from service, or transfer of DPV#2 rights of way to LADWP.~~Earliest of (i) in-service of DPV#2 line, (ii) the in-service date of any other new transmission line connecting Palo Verde to Devers in which LADWP has obtained an ownership interest or entitlement, (iii) the date DPV#1 is permanently removed from service, (iv) 4 years after CPUC approval to transfer DPV#2 rights of way to LADWP or (v) 12 months notice by LADWP.	368 MW
~~21~~ 19.	Palo Verde - Sylmar	LADWP	Bi-dir.	Exchange Agreement	219	5/31/2012	100 MW
~~22~~ 20.	Sylmar - Devers	LADWP	Bi-dir	Exchange Agreement	219	When DPV#1 is removed from service, or if DPV#2 is built, the date DPV#2 is removed from service	368 MW
~~23~~ 21.	Palo Verde - Devers Devers - Valley Valley - Serrano Serrano - SONGS	IID, APS, SDG&E	Bi-Dir.	Mutual Assistance Transmission Agreement	174	On 2034 or sooner by agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-

							Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in an operating bulletin.
~~24~~ 22.	Midway - Vincent 500 kV	PG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	633 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~25~~ 23.	Midway - SONGS	SDG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	161 MW
~~26~~ 24.	Midway - Vincent 500 kV	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25 or Pacific AC Intertie Agreement termination on 7-31-2007	320 MW
~~27.~~	~~Midway - Vincent 500 kV~~	~~CDWR~~	~~Bi-dir.~~	~~Amended and Restated Power Contract~~	~~112 First Revised~~	~~12/31/04~~	~~235 MW~~
~~28~~ 25.	Midway - Vincent 500 kV	PG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	655 MW
~~29~~ 26.	Midway - SONGS	SDG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20- SDG&E)	7/31/07	109 MW
~~30~~ 27.	Midway - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: term of PG&E Transmission Agreement, or 12/29/42 (50 yrs).	60 MW until 1/1/00, 60MW after 12/31/07
~~31.~~	~~COB - Tesla 500 kV~~	~~SMUD~~	~~Bi-dir.~~	~~Contract between California Companies and Sacramento Municipal Utility District for Extra High Voltage Transmission and Exchange Service~~	~~39~~	~~Useful life of existing Pacific Intertie per Amendment #2~~	~~200 MW~~
~~32~~ 28.	Pacific AC 500 kV Intertie	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25 or Pacific AC Intertie Agreement termination on 7-31-2007	320 MW
~~33.~~	~~COB-Sylmar - Rio Hondo~~	~~Azusa~~	~~To Sylmar and Rio Hondo~~	~~Pacific Intertie Firm Transmission Service~~	~~377~~	~~Earlier of 10/31/03, or upon Azusa's 1-year notice given after 1/1/02~~	~~28 MW May-October of 1998, 15 MW May-October thereafter~~
~~34.~~	~~COB - Sylmar~~	~~Banning~~	~~To Sylmar~~	~~Pacific Intertie Firm Transmission Service~~	~~383.1~~	~~Earlier of 10/31/03, or upon Banning's 1-year notice given after 1/1/02~~	~~10 MW May-October of 1998, 5 MW May-October thereafter~~
~~35.~~	~~COB - Sylmar-Vista~~	~~Colton~~	~~To Sylmar and Vista~~	~~Pacific Intertie Firm Transmission Service~~	~~366~~	~~Earlier of 10/31/03, or upon Colton's 1-year notice given after 1/1/02~~	~~15 MW May-October~~

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~36~~ 29.	SONGS - Vista	Riverside	To Vista	SONGS 2 & 3 Firm Transmission Service Agreement	393	~~12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~ 180 day notice by Riverside or SONGS Participation termination	42 MW ~~(per 1997 Edison – Riverside Restructuring Agreement).~~.
30 ~~37~~.	Victorville/Lugo - Midway	MSR	~~Bi-Dir.~~ S-N	~~Amended and Restated~~ Firm Transmission Service Agreement (Victorville/Lugo-Midway)	339 ~~First Revised~~	Earlier of: five-year notice by MSR, or life of Mead-Adelanto 500 kV Transmission Project	150 MW
~~38~~ 31.	Victorville/Lugo - Vista	Riverside	To Vista	Intermountain Power Project Firm Transmission Service Agreement	391	~~12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~ 180 day notice by Riverside or IPP Participation termination	156 MW ~~(per 1997 Edison – Riverside Restructuring Agreement).~~
~~39~~ 32.	Victorville/Lugo - Rio Hondo	Azusa	To Rio Hondo	PVNGS Firm Transmission Service Agreement	373	Earliest of: ~~termination agreement,~~ Azusa's 1-year notice given after 1/1/02, termination of PVNGS entitlement, or termination of PVNGS participation.	4 MW
~~40~~ 33.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	To Banning	PVNGS Firm Transmission Service Agreement	379	Earliest of: ~~agreement to terminate, or~~ Banning's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW
~~41~~ 34.	Victorville/Lugo - Vista	Colton	To Vista	PVNGS Firm Transmission Service Agreement	362	Earliest of: ~~agreement to terminate, or~~ Colton's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~42~~ 35.	Victorville/Lugo - Vista	Riverside	To Vista	PVNGS Firm Transmission Service Agreement	392	~~12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~ Earliest of: Riverside's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	12 MW ~~(per 1997 Edison – Riverside Restructuring Agreement).~~
~~43~~ 36.	Victorville/Lugo –Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360	Terminates with permanent removal of Mead-Adelanto from service	11 MW
~~44.~~	~~Victorville/Lugo - Laguna Bell~~	~~Vernon~~	~~Bi-dir.~~	~~Victorville-Lugo Firm Transmission Service~~	~~360~~	~~Up to term of agreement~~	~~64 MW~~
~~45~~ 37.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	Bi-dir.	Sylmar Firm Transmission Service Agreement	380	Earliest of ~~agreement to terminate, or~~ Banning's 1-year notice given after 1/1/02, or termination of Bannings interest in San Juan #3.	5 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~46~~ 38.	Victorville/Lugo - Rio Hondo	Azusa	to Rio Hondo	Pasadena FTS	374	Earliest of ~~agreement to terminate, or~~ Azusa's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	14 MW
~~47~~ 39.	Victorville/Lugo - Vista	Colton	to Vista	Pasadena FTS	363	Earliest of ~~agreement to terminate, or~~ Colton's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	18 MW
40 ~~48~~.	Sylmar - Rio Hondo	Azusa	To Rio Hondo	1995 San Juan Unit 3 FTS Agreement	376	Earlier of: termination of Azusa's interest in San Juan Unit #3 or Azusa's 1-year notice given after 1/1/02	~~Sum of 10 MW continuous plus 15 MW (May through October 1999 through 2003) (Per 1997 Edison – Azusa Restructuring Agreement)~~ 10 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~49~~ 41.	Sylmar - Goodrich	Pasadena	~~Sylmar-Goodrich~~ Bi-dir	Pasadena-Edison 230-kV Interconnection and Transmission Agreement	55	8/4/10	200 MW; Edison also responsible for delivery of up to 15 MW of Azusa Hydro Energy to Pasadena at Goodrich
~~50~~ 42.	Sylmar - Vista	Colton	Bi-dir.	Sylmar Firm Transmission Service Agreement	364	Earliest of: ~~agreement to terminate, or~~ Colton's 1-year notice given after 1/1/02, or termination of Idaho service contract.	3 MW
~~51~~ 43.	Sylmar - Midway	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Termination of Vernon COTP Ownership~~Earlier of: termination of PG&E Transmission Agreement, or 12/29/42 (50 yrs).~~	93 MW until 1/1/00, 93MW after 12/31/07
~~52~~ 44.	Sylmar - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	~~Earlier of: term of PG&E Transmission Agreement or 12/29/42 (50 yrs).~~ Termination of Vernon COTP Ownership	~~93 MW until 12/31/02, 60 MW after 12/31/02~~ 60 MW
~~53~~ 45.	Sylmar - SONGS	SDG&E	To SDG&E	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	100 MW
~~54~~ 46.	Sylmar - SONGS	SDG&E	To Sylmar	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	105 MW
~~55.~~	~~Sylmar - Vincent~~	~~CDWR~~	~~Bi-dir.~~	~~Amended and Restated Power Contract~~	~~112 First Revised~~	~~12/31/04~~	~~120 MW~~
~~56~~ 47.	Sylmar - Mead	PG&E	To Mead.	~~Amended and Restated~~ Edison-PG&E Transmission Agreement	256 ~~First Revised~~	7/31/07	Up to 200 MW of FTS.
~~57.~~	~~Point of Delivery: COB or NOB~~	~~BPA~~	~~S-N~~	~~Long Term Power Sales & Exchange Agreement~~	~~222~~	~~Per five year notice from BPA dated 10/29/1999, contract will terminate early on 11/1/2004~~	~~Up to 850 MW under the exchange modes.~~

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~58.~~	~~Point of Delivery: Midway or 500 kV bus at Vincent~~	~~CDWR~~	~~S-N~~	~~Amended and Restated Capacity Exchange Agreement~~	~~148 First Revised~~	~~12/31/2004~~	~~Depending on time and day: Minimum=225 MW Maximum=1550 MW for both the Power Contract and Capacity Exchange Agreement~~
~~59.~~	~~Point of Delivery: Midway or 500 kV bus at Vincent~~	~~CDWR~~	~~S-N~~	~~Amended and Restated Power Contract~~	~~112 First Revised~~	~~12/31/2004~~	~~Included under Capacity Exchange Agreement Contract Amount Column~~
~~60.~~	~~Point of Delivery: Palo Verde, Four Corners, Moenkopi~~	~~Tucson~~	~~W-E~~	~~Amended and Restated Tucson Power Exchange Agreement~~	~~271 First Revised~~	~~5/14/2005~~	~~110 MW~~
~~61~~ 48.	Hoover - Mead	WAPA	Bi-dir.	Lease of Two 230-kV Transmission Lines Between Hoover Power Plant and Mead Substation	304	9/30/2017 or upon 3-years' notice by WAPA; WAPA entitled to renew through life of Hoover.	Entire capacity leased to WAPA.
~~62~~ 49.	Calectric – Vincent	CDWR	To Vincent	Amended and Restated CDWR Devil Canyon Power Plant Additional Facilities and Firm Transmission Service Agreement	421	Life of Plant	120 MW
50 ~~63.~~	Mojave Siphon (Vista) - Vincent	CDWR	To Vincent	CDWR Mojave Siphon Additional Facilities and Firm Transmission Service Agreement	342	Life of Plant	28 MW
~~64.~~	~~Vincent - Oso~~	~~CDWR~~	~~to Oso~~	~~Amended and Restated CDWR Power Contract~~	~~112 First Revised~~	~~12/31/2004~~	~~72 MW~~
~~65.~~	~~Vincent - Pastoria~~	~~CDWR~~	~~to Pastoria~~	~~Amended and Restated CDWR Power Contract~~	~~112 First Revised~~	~~12/31/2004~~	~~787 MW~~
~~66.~~	~~Warne - Vincent~~	~~CDWR~~	~~To Vincent~~	~~Amended and Restated CDWR Power Contract~~	~~112 First Revised~~	~~12/31/2004~~	~~82 MW~~
~~67.~~	~~Vincent - Pearblossom~~	~~CDWR~~	~~To Pearblossom~~	~~Amended and Restated CDWR Power Contract~~	~~112 First Revised~~	~~12/31/2004~~	~~152 MW~~
51	Blythe - Cibola, &	APS	To APS Load	~~Amended and Restated~~ Firm	348 ~~First~~	Upon 3-year notice by APS, or 10	Presently ~~4.2~~5.1

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~68.~~	Ehrenberg ~~(Buckskin service does not go through ISO system)~~			Transmission Service (Blythe Accounts)	~~Revised~~	year notice by Edison	MW, 7 MW max.
~~69.~~	~~Malin – Round Mountain - Tracy~~	~~USBR (WAPA), California Companies~~	~~Bi-directional~~	~~USBR Contract with California Companies for Extra High Voltage Transmission And Exchange Service~~	~~37~~	~~1/1/2005~~	~~400 MW~~
~~70.~~	~~COB – Midway~~	~~State of CA. (CDWR), California Companies~~	~~Bi-directional~~	~~Contract between State of California and California Companies for the Sale, Interchange, and Extra High Voltage Transmission of Electrical Capacity and Energy~~	~~38~~	~~1/1/2005~~	~~300 MW~~

APPENDIX B.2

SDG&E's List of Contract Encumbrances[1]/[2]

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey ~~Tap~~ (3 lines) ~~- Mission~~ - Talega (2 lines) ~~- Encina~~
79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy without charge.

[1] An additional encumbrance pertaining to Local Furnishing Bonds that does not fit into the format for existing contract encumbrances is set forth at pages SDG&E App. B-1 through B-3 hereof.

[2] An additional encumbrance pertaining to SDG&E's lien of Mortgage and Deed of Trust that does not fit into the format for existing contract encumbrances is set forth at page SDG&E App. B-4 hereof.

78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031	In the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E Transmission System Participation Agreement	IID		June 24, 2051	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E -- 85.64%; and IID -- 14.36%.
78-003	APS-SDG&E Transmission System Participation Agreement	APS		July 31, 2031	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS -- 11%; SDG&E ~~--~~ ~~69~~76.22%; IID ~~--~~ ~~20~~12.78%.
QFD000.016	Power Sale Agreement between SDG&E-City of Escondido for the Rincon Indian Reservation	City of Escondido	76	Agreement to be terminated effective upon FERC acceptance of Notice of Termination.	Obligates SDG&E to sell and deliver electricity at stated prices to the City of Escondido for resale to the United States Indian Services at the Rincon Indian Reservation.

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO TRANSMISSION MAINTENANCE STANDARDS

TABLE OF CONTENTS

1. DEFINITIONS[1]

Availability - A measure of time a Transmission ~~Facility~~Line Circuit under ISO Operational Control is capable of providing service, whether or not it actually is in service.

Availability Measures - ~~The frequency and accumulated duration of Forced Outages(IMS) for each of the~~Within each Voltage Class in a calendar year: 1) the average Forced Outage(IMS) frequency for all Transmission Line Circuits~~ within a Voltage Class for a given calendar year~~, 2) the average accumulated Forced Outage(IMS) duration for only those Transmission Line Circuits with Forced Outages(IMS), and 3) the proportion of Transmission Line Circuits with no Forced Outages(IMS).

Availability Measure Targets - The Availability performance goals jointly established by the ISO and a PTO for that PTO's Transmission Facilities.

~~*Forced Outage(IMS)* — A Forced Outage(IMS) occurs when a Transmission Facility is in an Outage(IMS) condition regardless of duration and: (1) there is no Scheduled Outage request in effect with respect to that period; or (2) the Transmission Facility is in an Outage(IMS) condition for a period that exceeds the period specified in the Scheduled Outage request, in which case a Forced Outage(IMS) is deemed to exist for the balance of the period, unless the PTO requests and is granted an extension to the approved Scheduled Outage request.~~

[1] A term followed by the ~~supercript~~superscript "(IMS)" denotes a term which has a special, unique definition in this Appendix C.

~~*ISO Maintenance Guidelines* - Criteria presented herein which are to be followed by each PTO in preparing its PTO Maintenance Practices.~~
Forced Outage$^{(IMS)}$ – An event that occurs when a Transmission Facility is in an Outage$^{(IMS)}$ condition for which there is no Scheduled Outage$^{(IMS)}$ request in effect.

~~*ISO*~~*ISO Transmission Maintenance Standards* - ~~Those maintenance standards which result from the combination of each PTO's Maintenance Practices and their respective Availability Measures~~The Maintenance standards set forth in this Appendix C.

Maintenance - Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities performed with respect to Transmission Facilities.

Maintenance Practices - A confidential description of methods used by a PTO, and adopted by the ISO, for the Maintenance of that PTO's Transmission Facilities.

Maintenance Procedures – Documents developed by the Transmission Maintenance Coordination Committee ~~- A committee responsible for recommending to the ISO modifications to and implementation of the ISO~~for use by the ISO and the PTOs to facilitate compliance with the ISO Transmission Maintenance Standards. ~~The committee shall be organized and operate in accordance with Section 7.0 of this document~~These documents shall serve as guidelines only.

Outage$^{(IMS)}$ - Any interruption of the flow of power in a Transmission Line Circuit between any terminals under ISO Operational Control.

PTO - A Participating ~~Transmission Owner~~TO as defined in Appendix D of the Transmission Control Agreement.

~~*PTO Maintenance Practices* - A description of methods used by a PTO for the Maintenance of each substantial type of Transmission Facility or component in its system which is under the Operational Control of the ISO. The PTO Maintenance Practices are to be prepared in accordance with the ISO Maintenance Guidelines.~~

Scheduled Outage$^{(IMS)}$ - The removal from service of ~~a~~ Transmission ~~Facility under ISO Operational Control to perform work on specific components~~Facilities in accordance with the requirements of Section 7.1 of the Transmission Control Agreement and the applicable provisions of the ISO Tariff and ISO Protocols.

~~*Section 348 Criteria* - The criteria for maintenance standards established by Section 348 of the California Public Utilities Code, as in effect from time to time, to "provide for high quality, safe and reliable service", taking into consideration "cost, local geography and weather, applicable codes, national electric industry practices, sound engineering judgment, and experience".~~

~~*Stations* - Facilities under the Operational Control of the ISO for~~ *Station* – Type of Transmission Facility used for such purposes ~~such~~ as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities - All equipment and components transferred by a PTO to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and ~~system protection equipment~~associated facilities.

Transmission Line Circuit - The continuous set of transmission conductors, under the ISO Operational Control, located primarily outside of a Station, and apparatus terminating at interrupting devices, which would be isolated from the transmission system following a fault on such equipment.

Transmission Maintenance Coordination Committee ("TMCC") - The committee described in Section 7 of this Appendix C.

Voltage Class - The voltage to which operating, performance, and ~~maintenance~~Maintenance characteristics are referenced. Voltage Classes are defined as follows:

Voltage Class	Range of Nominal Voltage
69 kV	≤ 70 kV
115 kV	110 - 161 kV
230 kV	200 - 230 kV
345 kV	280 - 345 kV
500 kV	500 kV
HVDC	HVDC

Capitalized terms, not expressly defined above, are used consistently with the definitions provided in the Transmission Control Agreement and the ISO Tariff.

2. INTRODUCTION

~~These standards were prepared by the ISO~~This Appendix C delineates the ISO Transmission Maintenance Standards and has been developed through a lengthy consensus building effort involving ~~a diverse group of stakeholders (i.e., the ISO Maintenance Standards task force).~~

~~2.1. Objective~~

~~The Maintenance of Transmission Facilities has several objectives:~~

- ~~Ensuring that the safety and Availability performance levels inherent to the Transmission Facilities are achieved,~~
- ~~Restoring the safety and Availability to the levels inherent to the Transmission Facilities when degradation has occurred,~~
- ~~Gathering information that can be of use as the basis for identifying improvements to those Transmission Facilities whose Availability performance is inadequate,~~
- ~~Gathering information that can be used as the basis for optimizing and forecasting Maintenance for Transmission Facilities,~~
- ~~Extending the useful life of the Transmission Facilities while maintaining their inherent levels of Availability, and~~
- ~~Achieving the aforementioned objectives at a minimum total cost for Maintenance and Outages.~~

~~The ISO Maintenance Standards address the following topics:~~

- ~~Transmission Facilities Covered by the ISO Maintenance Standards;~~
- ~~Availability Measures ;~~
- ~~Availability Measure Targets;~~
- ~~ISO Maintenance Guidelines for PTO Maintenance practices;~~
- ~~Qualifications of Maintenance Personnel;~~
- ~~Maintenance Record Keeping and Reporting;~~
- ~~Establishment of a Maintenance Coordination Committee;~~
- ~~Process for the Revision of the ISO Maintenance Standards;~~
- ~~Incentives and Penalties for PTO Availability Performance;~~
- ~~Compliance with Laws and Regulations; and~~
- ~~Dispute Resolution. For certain aspects of Maintenance, these Standards delineate specific requirements and responsibilities (e.g., requirements for PTO inspection and Maintenance records), for others they provide guidelines (e.g., contents of PTO Maintenance Practices documents), and for others they describe processes (e.g., review process for PTO Maintenance Practices documents) to be enacted to achieve the desired results~~initially the ISO Maintenance Standards Task Force, and currently the TMCC.

Flexibility in establishing these ISO Transmission Maintenance Standards is implicit in the goal of optimizing Maintenance across a system characterized by diverse environmental and climatic conditions, terrain, equipment, and design practices. To provide for flexibility while ensuring the reasonableness of each PTO's approach to Maintenance, ~~the~~each PTO will prepare its own Maintenance Practices that shall be consistent with the requirements of these ISO Transmission Maintenance Standards ~~are founded on two basic precepts: 1) the~~. The effectiveness of each PTO's Maintenance Practices will be gauged through ~~an~~the Availability performance monitoring system~~, and 2) the adequacy of each~~. Each PTO's adherence to its Maintenance Practices will be assessed through ~~ISO review. Each PTO's Maintenance Practices will serve as the ISO's Maintenance Standards for the Transmission Facilities covered therein. The PTO Maintenance Practices ensure a reasonable level of~~

~~Maintenance during the short term while Availability is used to monitor long term performance.~~an ISO review.

~~It is the belief of the ISO~~In developing these ISO Transmission Maintenance Standards ~~task force~~, both the ISO Maintenance Standards Task Force and TMCC determined that it is impractical ~~for the ISO~~ to develop and/or impose on the ~~PTO's~~PTOs a single uniform set of ~~detailed descriptions of~~prescriptive practices delineating ~~condition~~conditions or time-based schedules for various Maintenance activities that account for the myriad of equipment, operating conditions, and environmental conditions within the ISO ~~grid~~Controlled Grid. For this reason, ~~the~~these ISO Transmission Maintenance Standards provide ~~ISO Maintenance Guidelines to be followed by each PTO in preparing PTO Maintenance Practices for its Transmission Facilities.~~ requirements for the PTOs in preparing their respective Maintenance Practices.

~~2.2. Availability~~

2.1. OBJECTIVE

This Appendix C provides for a high quality, safe, and reliable ISO Controlled Grid by meeting the following objectives:

- Ensuring that the Availability performance levels inherent to the Transmission Facilities are maintained,
- Restoring Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Economically extending the useful life of the Transmission Facilities while maintaining inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum reasonable total cost for Maintenance with the intent of minimizing customer impacts.

2.2. AVAILABILITY

ISO ~~grid reliability is a function of the Availability of Transmission Facilities owned and operated by its PTO's. The key to the effectiveness of the ISO Maintenance Standards is the establishment of a consistent measure of Transmission Facility Availability (Availability Measures") and the initial setting of the Availability Measure Targets as well as periodic revisions of those targets. By measuring Availability the ISO is able to monitor the effectiveness of Maintenance. While the ISO is concerned with grid reliability,~~Controlled Grid reliability is a function of a complex set of variables, including ~~the~~ accessibility of alternative ~~load paths, speed and sophistication of protective equipment,~~paths to serve Load, Generating Unit availability, Load forecasting and resource planning; speed, sophistication and coordination of protection systems; and the Availability of Transmission Line Circuits~~, and therefore is indirectly related to Maintenance. Thus, Availability will be~~ owned by the PTOs. Availability Measures have been chosen as the principal determinant of each PTO's ~~performance under the ISO~~ Maintenance ~~Standards~~effectiveness.

When using Availability Measures as a general gauge of Maintenance ~~adequacy~~effectiveness, several things must be ~~kept in mind~~considered to avoid misinterpreting performance. ~~The most important consideration is that across the ISO grid, the vast majority of all Forced Outages(IMS) are due to random/chance~~ Availability is a function of several variables, including Transmission Facility Maintenance, initial design, extreme exposure, capital improvements, and improvements in restoration practices. These factors should be taken into account when assessing Availability Measures and Maintenance effectiveness. It is important to consider that Maintenance is one of many variables that impact changes in Availability. For example, certain Forced Outages(IMS) that impact Availability may be due to events that generally cannot be controlled by Maintenance. ~~It is important to recognize that only a small percentage of all Forced Outages(IMS) can be controlled through Maintenance (i.e. activities that do not change the basic configuration of Transmission Facilities). This principle assumes the PTO is performing a reasonable level of Maintenance consistent with Good Utility~~

~~Practice. If an unreasonably low level of Maintenance is performed for a sufficient period of time, Availability will decline. However, if a level of~~

If Availability Measures are either improving or declining, it is important to investigate the cause(s) and any trends that are causing change before drawing conclusions. If Maintenance is being performed~~,~~ by a PTO consistent with Good Utility Practice, increasing Maintenance activities by a significant order ~~will~~may not result in a corresponding increase in Availability and if Maintenance is not performed consistent with Good Utility Practice, Availability may decline. Thus, while Maintenance is important to ~~ensuring~~ensure Availability, ~~drastic~~unless a PTO fails to perform Maintenance on a basis consistent with Good Utility Practice, significant increases in Maintenance activities will generally not lead to substantial improvements in ~~Transmission Facility~~ Availability and associated ~~grid~~ISO Controlled Grid reliability.

A variety of techniques can be used to monitor ~~performance, however~~Maintenance effectiveness. However, techniques that do not account for random variations in processes have severe limitations in that they may yield inconsistent and/or erroneous assessments of ~~performance~~Maintenance effectiveness. To account for random/chance variations while enabling monitoring for shifts and trends ~~in performance~~, control charts have been widely accepted ~~as an effective means for monitoring performance~~and utilized. Control charts are statistically- based graphs which illustrate both an expected range of performance for a particular process based on historical data, and discrete measures of recent performance. The relative positions of these discrete measures of recent performance and their relationship to the expected range of performance are used to gauge ~~the adequacy of performance. Availability is affected by several factors only one of which is Maintenance. In fact, for most Transmission Line Circuits only a small fraction of Forced Outages~~~~(IMS)~~ ~~can be attributed to phenomenon that could be controlled or avoided through Maintenance. Many more Forced Outages~~~~(IMS)~~ ~~are attributable to random/chance events than Maintenance-related items. Therefore, while monitoring Availability as a gauge of Maintenance adequacy is useful for evaluating long term trends, care must be taken to avoid reading too much~~

~~into the correlation of Availability to Maintenance since so many additional variables also impact Availability.~~Maintenance effectiveness.

~~The fundamental performance measures selected as the basis for developing an Availability performance monitoring system are the annual accumulated duration and frequency of certain types of Outages for each Transmission Line Circuit under the ISO's Operational Control. To enhance the Availability performance monitoring system's~~To enhance the use of Availability Measures as a gauge of Maintenance ~~adequacy~~effectiveness, it ~~was~~is necessary to exclude certain ~~Outage(IMS) types from the determination of the performance measures. Those~~types of Outages(IMS). These excluded Outages(IMS), as set forth in more detail in Section 4.1.3 of this Appendix C, are:

- Scheduled Outages(IMS);
- Outages(IMS) classified as "Not a Forced Outage" in the Maintenance Procedures;
- Forced Outages(IMS) caused by events originating outside the PTO's system; ~~and~~or
- Forced Outages(IMS) demonstrated to have been caused by earthquakes.

Additionally, as described in Section 4.1.2 of this Appendix C, the Forced Outage(IMS) duration used to calculate the Availability control charts has been capped at 72 hours so that excessively long Forced Outages(IMS) do not skew the data as to detract from the meaningfulness and interpretation of the control charts for accumulated Forced Outage(IMS) duration. This is not to say that an excessively long Forced Outage(IMS) is not a concern. Rather, such Forced Outages(IMS) should be investigated to assess the reasons for their extended duration.

~~The performance monitoring system~~Establishing Availability Measures requires each PTO to use ~~of~~ separate control charts for each Voltage Class ~~and PTO~~. Existing Forced Outage(IMS) data contains significant differences in the Availability ~~performance~~ between Voltage Classes and between PTOs. These differences may be attributable to factors such as the uniqueness of operating environments, Transmission Facility designs, and PTO operating policies. ~~However, regardless~~Regardless of the cause of

~~the~~these differences, review of the Forced Outage$^{(IMS)}$ data makes it eminently apparent that ~~the performance~~ differences are such that no single set of control chart parameters for a particular Voltage Class could be applied to all PTOs.

Three types of control charts ~~will be constructed~~are utilized to provide a complete representation of historical Availability ~~performance~~Measures, and to provide a benchmark against which future ~~performance~~Availability Measures can be gauged. The three types of control charts for each PTO and Voltage Class are:

- The annual average Forced Outage$^{(IMS)}$ frequency for all Transmission Line Circuits;
- The annual average accumulated Forced Outage$^{(IMS)}$ duration for those Transmission Line Circuits which experience Forced Outages$^{(IMS)}$; and
- The annual proportion of Transmission Line Circuits that experienced no Forced Outages$^{(IMS)}$.

These three control charts ~~will~~ assist the ISO and ~~PTO's~~PTOs in assessing the ~~performance of~~Maintenance effectiveness of each Voltage ~~Classes~~Class over time. To accommodate this process on a cumulative basis, data ~~are~~is made available to the ISO by each PTO at the beginning of ~~a~~each new calendar year to assess ~~the performance of the~~ past calendar years.

~~2.3. ISO Maintenance Guidelines~~

2.3. MAINTENANCE DOCUMENTATION REQUIREMENTS

Two specific requirements regarding Maintenance documentation ~~have been~~are incorporated into ~~the~~these ISO Transmission Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance ~~practices (PTO Maintenance~~ Practices~~)~~ to the ISO. Second, these standards require that each PTO ~~maintain~~retain Maintenance records as set forth in Section 6.1 of this Appendix C and make those records available to the ISO as set forth in the

Maintenance Procedures, in order to demonstrate compliance with each element of its ~~PTO~~ Maintenance Practices.

~~To outline the fundamental requirements for, and to promote consistency in the PTO Maintenance Practices, these standards provide guidelines for the preparation and maintenance of the PTO Maintenance Practices. These ISO Maintenance Guidelines provide for flexibility in approach to Maintenance, but also require the description of certain specific Maintenance practices. The guidelines require that the PTO's provide descriptions of the various Maintenance activities, schedules and condition triggers for performing the Maintenance, and samples of any checklists, forms, or reports used for Maintenance activities.~~

~~2.4. Data Standards~~

2.4. AVAILABILITY DATA STANDARDS

To facilitate processing ~~of~~Forced Outage(IMS) data for the Availability ~~performance monitoring system~~Measures, and to enable consistent and equitable interpretation of PTO Maintenance records by the ISO, these standards address the need for data recording and reporting. The ~~ISO and PTO's have committed to developing~~TMCC has also developed standardized formats for transmitting Forced Outage(IMS) data to the ISO for the Availability ~~performance monitoring system~~Measures. These standard formats are ~~to be finalized within the first 60 days of 1998. Additionally, the ISO and PTO's have agreed to develop and implement a standard Maintenance~~provided in the Maintenance Procedures. To facilitate review of the data by the ISO, the TMCC has developed a standard Availability Measures reporting system ~~by the end of the third year of operation of the ISO~~detailed in the Maintenance Procedures and in Section 4 of this Appendix C. This system will provide for consistent gathering of information that can be used as the basis for ~~optimizing and forecasting maintenance of Transmission Facilities. The development of such a Maintenance reporting system is consistent with fostering the spirit of cooperation among the ISO and the PTO's as it may eventually aid in the resolution of performance problems, and provide the basis for research on an~~

~~ISO grid-wide basis to identify opportunities to enhance Transmission Facility Maintenance~~analyzing Availability Measures trends.

~~2.5. Applicability of Incentives and Penalties~~

~~Cooperation and collaboration among the PTOs responsible for ensuring the Availability of the Transmission Facilities comprising the ISO grid are needed to ensure the most reliable grid possible. Therefore, the ISO Maintenance Standards task force believes that a formal program of incentives and penalties tied purely to PTO Maintenance may hinder needed cooperation among PTOs. As a result, the ISO Maintenance Standards task force recommends that no such program be instituted initially by the ISO.~~

~~Further, the task force recognizes the need for the ISO to enforce reasonable Maintenance to ensure Availability in the case that: 1) a PTO exhibits degradation in Availability performance due to Maintenance, 2) a PTO does not comply with its PTO Maintenance Practices, or 3) a PTO is grossly or willfully negligent with regards to Maintenance. Therefore, it is the position of the ISO Maintenance Standards task force that it is reasonable for the ISO to establish penalties for such conditions. In the absence of a formal program of incentives and penalties, the task force acknowledges the ISO's right to pursue sanctions for cause on a case by case basis.~~

~~Availability is a useful and tractable means for monitoring performance, however, the electric utility industry as a whole has little experience in using Availability to gauge the adequacy of Maintenance. Further, because the industry in general has not carefully managed historical Outage[(IMS)] data to the degree that is necessary to make them useful for performance monitoring, there are varying limitations with regards to the accessibility and reliability of Outage[(IMS)] data among PTOs. Also, the impact on Availability when a new entity, namely the ISO, assumes Operational Control of the grid is unknown. Thus, it is the position of the ISO Maintenance Standards task force that the Availability performance monitoring system will be implemented and used to gauge Availability performance beginning on the ISO Operations Date. However, the system needs to be used and updated during a five year phase in period to be considered for use in a program of incentives and penalties for Availability performance.~~

~~Availability is a function of several variables including Transmission Facility~~

~~Maintenance, capital improvements, and improvements in restoration practices. If a PTO is exercising a reasonable level of Maintenance, yet the Availability performance of a Voltage Class or individual Transmission Line Circuit is inadequate for the purposes of the ISO grid, then capital improvements or improvements in restoration practices may lead to greater Availability improvements than increased Maintenance. Therefore, assessing incentives and penalties on the basis of Availability as influenced by all of these variables may be a reasonable approach for influencing PTO's to improve the Availability of their Transmission Facilities where such improvements can be justified.~~

3. ~~TRANSMISSION~~ FACILITIES COVERED BY ~~THE~~THESE ISO TRANSMISSION MAINTENANCE STANDARDS

~~All Transmission Facilities transferred to the ISO, pursuant to the Transmission Control Agreement, shall be maintained in accordance with the ISO Maintenance Standards.~~ The ISO Transmission Maintenance Standards set forth in this Appendix C shall apply to all Transmission Facilities. Each PTO shall maintain its Transmission Facilities in accordance with its Maintenance Practices as adopted by the ISO in accordance with these ISO Transmission Maintenance Standards.

4. AVAILABILITY ~~STANDARD~~MEASURES

~~4.1. Introduction~~

~~The ISO shall monitor and measure each PTO's Availability for the Transmission Line Circuits under ISO Operational Control. The ISO shall use an Availability measurement system which consists of two primary components: 1) measures of the annual performance of each Voltage Class based on the performance of each of the Transmission Line Circuits comprising the Voltage Class, i.e. the Availability Measures; and 2) a set of threshold performance criteria for each Voltage Class, i.e. Availability Measure Targets. The Availability Measure Targets will be used to gauge the adequacy of the PTO's annual performance for each Voltage Class. Each PTO shall make an annual report to the ISO within 90 days from the end of each calendar year that describes its compliance with the Availability Measure Targets. In its report to the ISO,~~

~~supporting data based on Outage(IMS) records shall be included, justifying the Availability Measures reported for each Voltage Class.~~

4.1. CALCULATION OF AVAILABILITY MEASURES FOR INDIVIDUAL TRANSMISSION LINE CIRCUITS

~~4.2. Availability Measures~~

~~4.2.1. Calculation of Availability Measures for Individual Transmission Line Circuits~~

4.1.1 FREQUENCY AND DURATION

The calculation of the Availability Measures will be performed utilizing Forced Outage(IMS) data through December 31st of each calendar year. Separate Forced Outage(IMS) frequency and accumulated Forced Outage(IMS) duration Availability Measures shall be calculated as follows for each Transmission Line Circuit under ISO Operational Control within each Voltage Class. The calculations shall be performed annually for each of the Transmission Line Circuits utilizing all appropriate Forced Outage(IMS) data for the calendar year in question.

Forced Outage(IMS) Frequency:

The Forced Outage(IMS) frequency (f_{ik}) of the i^{th} Transmission Line Circuit shall equal the total number of Forced Outages(IMS) that occurred on the i^{th} Transmission Line Circuit during the calendar year "k". See Notes 1 and 2.

NOTES:

1. Multiple momentary Forced Outages(IMS) on the same Transmission Line Circuit in the span of a single minute shall be treated as a single Forced Outage(IMS) with a duration of one minute. When the operation of a Transmission Line Circuit is restored following a Forced Outage(IMS) and the Transmission Line Circuit remains operational for a period exceeding one minute, i.e., 61 seconds or more, followed by another Forced Outage(IMS), then these should be counted as two Forced Outages(IMS). Multiple Forced Outages(IMS) occurring as a result of a single event should be handled as multiple Forced Outages(IMS) only if subsequent operation of the Transmission Line Circuit between events exceeds one minute. Otherwise they shall be considered one continuous Forced Outage(IMS).

2. If a Transmission Line Circuit, e.g., a new Transmission Line Circuit, is only in service for a portion of a calendar year, the Forced Outage(IMS) frequency and accumulated duration data shall be treated as if the Transmission Line Circuit had been in service for the entire calendar year, i.e., the Forced Outage(IMS) data for that Transmission Line Circuit shall be handled the same as those for any other Transmission Line Circuit.

Accumulated Forced Outage(IMS) Duration:

The accumulated Forced Outage(IMS) duration in minutes shall be calculated as follows for each of the Transmission Line Circuits having a Forced Outage(IMS) frequency (f_{ik}) greater than zero for the calendar year "k":

$$d_{ik} = \sum_{j=1}^{f_{ik}} o_{ijk}$$

where

d_{ik} = accumulated duration of Forced Outages(IMS) (total number of Forced Outage(IMS) minutes) for the "ith" Transmission Line Circuit having a Forced Outage(IMS) frequency (f_{ik}) greater than zero for the calendar year "k".

f_{ik} = Forced Outage(IMS) frequency as defined above for calendar year "k".

o_{ijk} = duration in minutes of the "jth" Forced Outage(IMS) which occurred during the "kth" calendar year for the "ith" Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages(IMS) shall be capped as described in Section ~~4.2.2. "Capping of Forced Outage(IMS) Duration"~~ 4.1.2 of this Appendix C for the purposes of calculating the Availability Measures . In addition, certain types of ~~events/~~Outages(IMS) shall be excluded from the calculations of the Availability Measures as described in Section ~~4.2.3 "Excluded Events"~~4.1.3 of this Appendix C.

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Forced Outage(IMS) data reporting schemes, the PTO shall notify the ISO at the time of the change. In its annual report to the ISO, the PTO shall provide recommendations regarding if and how the Availability Measures and Availability Measure Targets should be modified to ensure that they (1) remain consistent with the modified Transmission Line Circuit identification or Forced Outage(IMS) data reporting scheme, and ~~that they~~(2) provide an appropriate gauge of ~~performance~~Availability.

~~**4.2.2. Capping of Forced Outage(IMS) Durations**~~

4.1.2. CAPPING FORCED OUTAGE(IMS) DURATIONS

The ~~durations~~duration of ~~individual~~each Forced ~~Outages~~Outage(IMS) which ~~exceed~~exceeds 72 hours (4320 minutes) shall ~~each~~ be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage(IMS) duration.

~~**4.2.3. Excluded Events**~~

4.1.3. EXCLUDED OUTAGES (IMS)

The following types of ~~events/~~Outages(IMS) shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- Scheduled Outages ~~which are scheduled, reviewed and approved by the ISO in accordance with the Transmission Control Agreement, and~~(IMS)
- Outages(IMS) classified as "Not a Forced Outage" in the Maintenance Procedures.

- Forced Outages(IMS) which: (1) were caused by events outside the PTO's system including ~~those~~ Outages(IMS) which originate in other TO systems, other electric utility systems, or customer equipment, ~~and~~ or (2) ~~those Forced~~are Outages(IMS) which can be demonstrated to have been caused by earthquakes.

~~**4.3. Targets for Availability Performance**~~

4.2. AVAILABILITY MEASURE TARGETS

The Availability Measure Targets described herein shall be phased in over a period of five calendar years beginning on the ~~ISO Operations Date~~date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement. The adequacy of each PTO's Availability ~~performance~~Measures shall be monitored through the use of charts ~~on which are plotted indices reflecting annual Availability performance~~. These charts, called control charts as shown in Figure ~~4.3.1,~~4.2.1, are defined by a horizontal axis with a scale of calendar years and a vertical axis with a scale describing the expected range of magnitudes of the index in question. Annual performance indices shall be plotted on these charts and a series of tests may then be performed to assess the stability of annual performance, shifts in performance and longer -term performance trends.

Control charts for each of the following indices shall be developed and utilized to monitor Availability ~~performance~~Measures for each Voltage Class within each PTO's system:

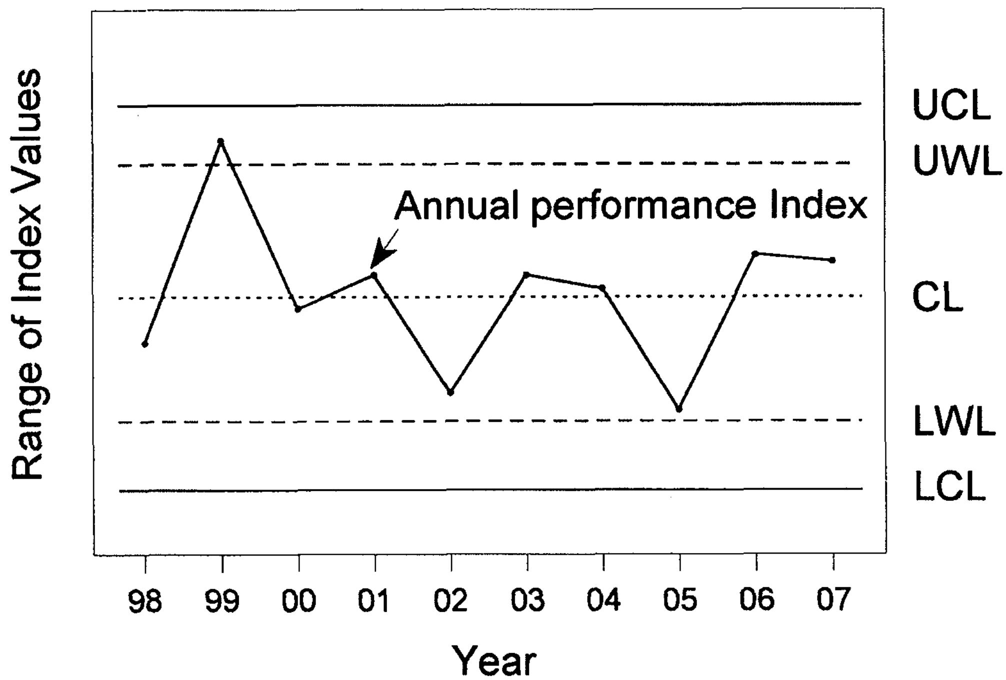

Figure ~~4.3.1~~4.2.1 Sample Control Chart

- Index 1: Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits.
- Index 2: Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS).
- Index 3: Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS).

The control charts incorporate a center control line (CL), upper and lower control limits (UCL and LCL, respectively), and upper and lower warning limits (UWL and LWL, respectively). The CL represents the average annual historical performance for a period prior to the current calendar year. The UCL and LCL define a range of expected performance extending above and below the CL. For the annual proportion of Transmission Line Circuits with no Forced Outages(IMS), the limits are based on standard control chart techniques for binomial proportion data. For the other two indices, bootstrap resampling techniques are used to determine empirical UCL and LCL at 99.75% and 0.25% percentile values, respectively, for means from the historical data. The bootstrap procedure is described in Section ~~4.3.2.~~4.2.2 of this Appendix C. Similarly, the UWL and LWL define a range of performance intending to cover the percentiles from 2.5% to 97.5%. The bootstrap algorithm is also used to determine these values. Thus, the UCL and LCL will contain about 99.5% of resampling means from the Voltage Class of interest. UWL and LWL will contain about 95% of the resampling means. These limits coincide with the usual choices for control charts when the means are approximately normal. Bootstrap estimation procedures are used here since the sampling means do not follow the ~~Normal~~normal distribution model. The bootstrap estimation procedures ensure consistent control chart limits by using a starting base number ("seed") for ~~it's~~its random number generator. Accuracy or reduced variances in the control chart limits are attained by using the average control chart limits generated from applying ten repetitions or cycles of the bootstrap sampling method. Collectively, the CL, UCL, LCL, UWL and LWL provide reference values for use in evaluating performance as described in Section ~~4.3.3.~~4.2.3 of this Appendix C.

For the special case where there is a Voltage Class with only one Transmission Line Circuit, individual and moving range control charts should be used for Index 1 and 2. The method used herein for calculating Index 3 is not applicable for those Voltage Classes containing less than six Transmission Line Circuits. The Maintenance ~~procedures recommended by the MCC and approved by the ISO Governing Board~~Procedures will be used by the PTOs to calculate Index 1, 2, or 3 where the methods provided herein do not apply. More information on the individual and moving range control charts can be found in the user manuals of the statistical software recommended by the ~~MCC~~TMCC and approved by the ISO Governing Board for use in creating the control charts .

~~4.3.1. Calculations of Annual Availability Performance Indices for Individual Voltage Classes~~

4.2.1. CALCULATIONS OF ANNUAL AVAILABILITY MEASURES INDICES FOR INDIVIDUAL VOLTAGE CLASSES

Separate annual Availability ~~performance~~Measures indices shall be calculated for each Voltage Class and each PTO as described below by utilizing the ~~Availability Measures~~ calculations discussed in Section ~~4.2.~~4.1 of this Appendix C.

Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits (Index 1):

$$F_{vc,k} = \frac{1}{N_k} \sum_{i=1}^{N_k} f_{ik}$$

where

$F_{vc,k}$ = frequency index for the Voltage Class, vc, (units = Forced Outages(IMS) /Transmission Line Circuit). The frequency index equals the average (mean) number of Forced Outages(IMS) for all Transmission Line Circuits within a Voltage Class for the calendar year "k".

N_k = number of Transmission Line Circuits in Voltage Class in calendar year "k". See Note 2, Section ~~4.2.1.~~4.1.1 of this Appendix C.

f_{ik} = frequency of Forced Outages(IMS) for the "ith" Transmission Line Circuit as calculated in accordance with Section ~~4.2.1~~4.1.1 of this Appendix C for calendar year "k".

Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for those Transmission Line Circuits with Forced Outages$^{(IMS)}$ (Index 2):

$$D_{vc,k} = \frac{1}{N_{o,k}} \sum_{i=1}^{N_{o,k}} d_{ik}$$

where

$D_{vc,k}$ = duration index for the Voltage Class (units = minutes/Transmission Line Circuit). The duration index equals the average accumulated duration of Forced Outages$^{(IMS)}$ for all Transmission Line Circuits within a Voltage Class which experienced Forced Outages$^{(IMS)}$ during the calendar year "k".

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section ~~4.2.1~~4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section ~~4.2.1.~~4.1.1 of this Appendix C.

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ for the "ith " Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) greater than zero for calendar year "k" as calculated in accordance with Section ~~4.2.1.~~4.1.1 of this Appendix C.

Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$ (Index 3):

$$P_{vc,k} = \frac{N_k - N_{o,k}}{N_k}$$

where

$P_{vc,k}$ = index for the proportion of Transmission Line Circuits for the Voltage Class with no Forced Outages$^{(IMS)}$ for the calendar year "k".

N_k = number of Transmission Line Circuits in Voltage Class for calendar year "k". See Note 2, Section ~~4.2.1.~~4.1.1 of this Appendix C.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section ~~4.2.1~~4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section ~~4.2.1.~~4.1.1 of this Appendix C.

~~4.3.2. Development of Limits for Performance Control Charts~~

4.2.2. DEVELOPMENT OF LIMITS FOR CONTROL CHARTS

The CL, UCL, LCL, UWL and LWL for the three control charts (Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits~~,~~; Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS)~~,~~; and Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)) on which the annual Availability ~~performance~~Measures indices are to be plotted shall be calculated as described below. The CL, UCL, LCL, UWL and LWL for each of the three control charts shall be determined using continuously recorded Forced Outage(IMS) data for the ten calendar year period immediately preceding the ~~ISO Operations Date, or immediately preceding the date a TO~~date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

In the event that a PTO does not have reliable, continuously recorded Forced Outage(IMS) data for this 10 calendar year period, ~~the~~that PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, ~~the~~that PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO ~~prior to February 1, 1998, or~~ within ~~30~~90 days after the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

The ISO shall periodically review the control chart limits and ~~appropriately modify them when necessary~~recommend appropriate modifications to each PTO in accordance with ~~Section 8.0, "Revision of ISO Maintenance Standards," of this document~~this Appendix C.

~~4.3.2.1.~~ 4.2.2.1. CENTER CONTROL LINES (CLs)

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability ~~performance~~Measures indices described in Section

~~4.3.1~~4.2.1 of this Appendix C except that the time period ~~for which data are to be included in the calculations~~ is expanded from a single calendar year to ~~the~~ ten calendar years, unless a shorter period is justified by ~~the~~a PTO, for the period ~~immediately preceding the ISO Operations Date, or immediately~~ preceding the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement. To account for this change, a count of Transmission Line Circuit years is included in the equations as shown below to enable derivation of CLs which represent average performance during a multi-year period.

CL for Annual Average Transmission Line Circuit Forced Outage(IMS) Frequency

$$CL_{fvc} = \sum_{k=1}^{Y} \sum_{i=1}^{N_k} f_{ik} \, / \, (\sum_{k=1}^{Y} N_k)$$

where

CL_{fvc} = center control line value for the Forced Outage(IMS) frequencies for each of the Transmission Line Circuits in the Voltage Class for ~~Y~~"Y" calendar years prior to the ~~ISO Operations Date, or the~~ date a TO becomes a PTO.

Y = number of calendar years prior to the ~~ISO Operations Date (or the~~ date a TO becomes a PTO~~)~~ for which the PTO has reliable, continuously recorded Forced Outage(IMS) data. Y=10 is preferred.

CL for Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS)

$$CL_{dvc} = \sum_{k=1}^{Y} \sum_{i=1}^{N_{o,k}} d_{ik} \, / \, (\sum_{k=1}^{Y} N_{o,k})$$

where

CL_{dvc} = center control line value for accumulated Forced Outage(IMS) duration for each of the Transmission Line Circuits in the Voltage Class for ~~Y~~"Y" calendar years prior to the ~~ISO Operations Date (or the~~ date a TO becomes a PTO~~)~~ in which the Forced Outage(IMS) frequency (f_{ik}) was greater than zero.

CL for Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)

$$CL_{Pvc} = \frac{\sum_{k=1}^{Y} (N_k - N_{o,k})}{\sum_{k=1}^{Y} N_k}$$

where

CL_{Pvc} = center control line value for the proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages(IMS) for ~~Y~~ "Y" calendar years prior to ~~the ISO Operations Date, or~~ the date a TO becomes a PTO.

~~4.3.2.2.~~4.2.2.2. UCLs, LCLs, UWLs ~~and~~AND LWLs

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for Voltage Classes Containing Four or More Transmission Line Circuits with Forced Outages(IMS) for Five or More Calendar Years

The UCLs , UWLs, LWLs, and LCLs for the control charts for each Voltage Class containing four or more Transmission Line Circuits with Forced Outages(IMS) shall be determined by bootstrap resampling methods as follows: The available historical data for Index 1 and 2 will each be entered into columns. ~~A~~ A "seed" is then selected prior to beginning the sampling process. The ISO assigns a number for the "seed" prior to each ~~years~~calendar year's development of the control charts. The "seed" allows the user to start the sampling in the same place and get the same results provided the data order hasn't changed. For Index 1, sampling with replacement will occur for the median number of ~~lines per~~Transmission Line Circuits per calendar year in a Voltage Class for the time period being evaluated. A sample, the size of which is the median number of all Transmission Line Circuits for the period being evaluated, is taken from the column of actual frequency values for all Transmission Line Circuits. A mean is calculated from this sample and the resulting number will be stored in a separate column. This process~~,~~ will be repeated 10,000 times in order to create a column of sampling means from the historical ~~data base~~database. The column of sampling means is then ordered from the smallest to largest means. From this column percentiles are determined for a UCL~~(~~ (99.75), a LCL~~(~~ (0.25), a UWL (97.5), and a

LWL (2.5). Thus, for one cycle, the limits are determined by resampling from the historical ~~data base~~database, calculating statistics of interest, in this case means, and then estimating appropriate limits from the resampling means. Ten cycles of this same process are necessary to get ~~10~~ten values each of UCLs, LCLs, UWLs, and LWLs. The average for the ten values of each limit is taken to provide the UCL, LCL, UWL, and LWL values used in analyzing annual performance. The procedure is repeated for Index ~~2~~2, forming means for the median number of ~~lines~~Transmission Line Circuits with Forced Outages(IMS) in this Voltage Class for the time period being evaluated. See **Bootstrapping - A Nonparametric Approach to Statistical Inference** (1993) by Christopher Z. Mooney and Robert D. Duval, Sage Publications with ISBN 0-8039-5381-X, and **An Introduction to the Bootstrap** (1993) by Bradley Efron and Robert J. Tibshirani, Chapman and Hall Publishing with ISBN 0-412-04231-2 for further information.

Consider an example to illustrate how the ~~Bootstrap~~bootstrap procedure works for one cycle of the ten required. Assume that a Voltage Class has approximately 20 Transmission Line Circuits per calendar year with a history of ten calendar years. Furthermore, assume that about 15 Transmission Line Circuits per calendar year experience Forced Outages(IMS). Therefore, there are 10 x 15 = 150 Forced Outage(IMS) durations available for bootstrap sampling. Place these 150 Forced Outage(IMS) durations in a column, say "outdur," ~~–~~ in a specified order . The order is automatically provided in the bootstrap algorithm developed by the ISO and made available to the PTO. The bootstrap algorithm will sample 15 rows from "outdur" with replacement. That is, any row may, by chance, be sampled more than once. From these 15 values determine the sample mean and place this in another column, say "boot". Repeat this sampling process 10,000 times adding the new means to "boot". The column "boot" now has 10,000 means from samples of size 15 from the original Forced Outage(IMS) duration data for this Voltage Class. The next step is to locate the appropriate percentiles from these means for use in determining the control chart limits for one cycle. This is accomplished by ordering the column "boot" from smallest -to -largest mean and restoring these ordered means in "boot". The percentiles which are needed are 99.75% (UCL), 97.50% (UWL), 2.50% (LWL) and 0.25% (LCL). These are easily estimated from the sorted means by finding the associated rows in the column "boot". For example, LWL will be estimated as the average of the 250th and 251st rows in column "boot". Likewise the other limits will be determined. Of course, the CL is the actual mean average for 15 ~~lines~~Transmission Line Circuits over the ten calendar years using the formulas in Section ~~4.3.2.1.~~4.2.2.1 of this Appendix C. This example is for one cycle. Nine more cycles of this process will establish the more accurate control and warning limits necessary to evaluate a PTO's annual performance.

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for All Other Voltage Classes

When data for less than four Transmission Line Circuits with Forced Outages$^{(IMS)}$ are available per calendar year in a Voltage Class for fewer than five calendar years, an exhaustive enumeration of all possible selections with replacement may need to be performed. This is because the number of possible samples for bootstrap resampling will be less than the aforementioned 10,000 resampling frequency used for Voltage Classes containing four or more Transmission Line Circuits with Forced Outages$^{(IMS)}$ for five or more calendar years. For example, if a Voltage Class has only two Transmission Line Circuits per calendar year for five calendar years, the data base will consist of 2*5 = 10 accumulated Forced Outage$^{(IMS)}$ durations assuming both Transmission Line Circuits experience ~~a~~one Forced Outage$^{(IMS)}$ or more per calendar year. Resampling two values from the column of ~~10~~ten yields only 10**2 = 100 possible means. Thus, bootstrap resampling of 10,000 would over-sample the original data 10,000/100 = 100 times.

For the general case, let M = the number of accumulated Forced Outage$^{(IMS)}$ durations (or Forced Outage$^{(IMS)}$ frequencies) from the historical ~~data base~~database. If n is the median number of Transmission Line Circuits per calendar year, there are M**n = U possible enumerated means for this Voltage Class. The procedure to determine the appropriate limits for a Voltage Class is to order the column containing "U" enumerated means from smallest to largest means. Then, the UCL, LCL, UWL, and LWL are determined from this vector as described above (i.e., at the 99.75, 0.25, ~~97. 5~~97.5, and ~~2. 5~~2.5 percentiles, respectively).

UCLs, LCLs, UWLs and LWLs for Index 3 When Number of ~~Lines~~Transmission Line Circuits is > 125

According to standard procedures for proportion control charts for ~~voltage classes~~Voltage Classes where the median number of ~~lines~~Transmission Line Circuits in service is greater than 125 for any given calendar year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the "kth" calendar year are determined using the normal approximation to the binomial distribution. The formulas are:

$$UCL = CL_{Pvc} + 3S_{Pvc,k} \qquad\qquad LCL = CL_{Pvc} - 3S_{Pvc,k}$$

UWL and LWL are calculated by replacing the "3" above with~~-a~~ "2".

and

$$S_{Pvc,k} = \sqrt{CL_{Pvc}(1 - CL_{Pvc}) / N_k}$$

where

$S_{Pvc,k}$ = standard deviation for the annual proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages(IMS) for each ~~(~~"kth"~~)~~ year of the ~~Y~~"Y" calendar years prior to ~~the ISO Operations Date, or~~ the date a TO becomes a PTO. If LCL or LWL is less than zero, they should be set to zero by default.

UCLs, LCLs, UWLs and LWLs for Index 3 when Number of ~~Lines~~Transmission Line Circuits is less than or equal to 125 and greater than or equal to six~~.~~

The UCLs, LCLs, UWLs, and LWLs for the control charts for each ~~voltage class~~Voltage Class shall be based on exact binomial probabilities for those ~~voltage classes~~Voltage Classes having equal to or more than six , but less than or equal to 125 median ~~transmission lines per year.~~Transmission Line Circuits per calendar year. A customized macro and a statistical software package approved by the ISO creates the proportion control charts. The macro determines the control limits and use of the exact binomial or the normal approximation to the binomial for computing the control chart limits. This macro ensures the UCL and LCL ~~contains~~ contain about 99.5% and the UWL and LWL ~~contains~~ contain about 95% of the binomial distribution. The percentile values of the UCL, UWL, LWL, and LCL are respectively 99.75%, 97.5%, 2.5%, and 0.25%.

The UCL, UWL, LWL, and LCL are calculated using the following formulas:

$$\mathbf{UCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{UWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{LWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{LCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

Where

~~P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas(i.e. P_2 = 0.9975 in the UCL formula and =0.025 in the LWL formula)~~

P_1 = A cumulative binomial probability that if not ~~representing~~equal to the ~~percentile~~P_2 value is representing the percentile value that is less than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_1 = ~~0.74~~0.99529 and is closest to the 99.75 percentile value~~ and represents~~, from the ~~99 percentile then~~low side, P_1 = ~~0.74~~0.99529 should be used in the UCL formula).

P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas (e.g., P_2 = 0.9975 in the UCL formula and = 0.025 in the LWL formula).

P_3 = A cumulative binomial probability that if not ~~representing~~equal to the ~~percentile~~P_2 value is representing the percentile value that is greater than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_3 = ~~0.82~~0.99796 and is closest to the 99.75 percentile value~~ and represents~~, from the ~~99.85 percentile~~high side, then P_3 = ~~0.82~~ 0.99796 should be used in the UCL formula).

X_1 = The number of ~~lines~~Transmission Line Circuits with no ~~outages~~Forced Outages(IMS) associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas~~.~~ (e.g. ~~If~~, if P_1 =

~~0.74~~ 0.99529 and represents the ~~99th~~closest percentile from below the 99.75 percentile for the case where ~~78 lines didn't have any outages~~19 Transmission Line Circuits had no Forced Outages(IMS), then X_1 = ~~78~~19 should be used in the UCL formula).

n = The median number of ~~lines~~Transmission Line Circuits that are in service in a given calendar year. This number remains the same in each of the UCL, UWL, LWL, and LCL formulas.

~~More information on the calculations of the proportion control chart limits is in the current ISO Transmission Facility Availability Performance Monitoring System Handbook.~~

~~4.3.3. Evaluation of Availability Performance~~

4.2.3. EVALUATION OF AVAILABILITY MEASURES PERFORMANCE

The control charts shall be reviewed annually by the ISO and PTOs in order to evaluate Availability Measures performance. The annual ~~performance~~ evaluation shall consist of an examination of each of the control charts to determine if one or more of the following four tests indicate a change in performance. The four tests have been selected to enable identification of exceptional performance in an individual calendar year, shifts in longer -term performance, and trends in longer -term performance.

Tests

- **Test 1:** The index value for the current calendar year falls outside the UCL or LCL.
- **Test 2:** At least v1 consecutive annual index values fall above the CL or v2 consecutive annual index values fall below the CL. The actual values of v1 and v2 will be output from the bootstrap resampling procedures. The choices for v1 and v2 are designed to keep the probability of these events less than one percent.

Table 1. Values of v1 and v2 for Percentiles of the CL in Specified Ranges

Percentile	v1	v2
35 - 39	10	5
40	10	6
41 - 43	9	6
44 - 46	8	6
47 - 48	8	7
49 - 51	7	7
52 - 53	7	8
54 - 56	6	8
57 - 59	6	9
60	6	10
61 - 65	5	10

Thus, for example, if for a particular Voltage Class the percentile of the historical CL is 55%, this ~~says~~Table indicates that the CL is located at the 55 percentile of all bootstrap means in the "boot" column. From Table 1, v1=6, and v2=8.

- **Test 3:** At least two out of three consecutive annual index values fall outside the UWL or LWL on the same side of the CL.
- **Test 4:** Six or more values are consecutively increasing or consecutively decreasing.

Therefore, Test 1 is designed to detect a short -term change or jump in the average level. Tests 2 and 4 are looking for long -term changes. Test 2 will detect a shift up in averages or a shift to a lower level. Test 4 is designed to detect either a trend of continuous increase in the average values or continuous decrease. Test 3 is designed to assess changes in performance during an intermediate period of three calendar years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three calendar year period. Together the four tests allow the ISO to monitor the ~~availability~~Availability performance of a Voltage Class for a PTO.

If none of these tests ~~indicates~~indicate that a change has occurred, performance shall be considered to be stable and consistent with past performance. If one or more of these tests indicates a change then Availability performance shall be considered as having improved or degraded relative to the performance defined by the control chart. Table ~~4.3.1~~4.2.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last calendar year's Availability performance indices did not trigger any of the four tests. If none of the four tests are triggered, the new limits will be constructed including the last calendar year's data.

The control chart limits may be modified each year to reflect the number of Transmission Line Circuits in service during that calendar year if necessary. However, it is suggested that unless the number of ~~lines~~Transmission Line Circuits changes by more than 30% from the previous calendar year, the use of the median number of ~~lines~~Transmission Line Circuits should continue. Consider an example~~. Suppose~~; suppose after the control chart has been prepared for a Voltage Class, next calendar year's data ~~arrive~~arrives with the number of ~~lines~~Transmission Line Circuits 30% higher than the median used in the past. New limits will be generated in order to assess the Availability performance for that calendar year.

For the special case where only one Transmission Line Circuit has a Forced Outage(IMS) in a Voltage Class during a calendar year, the assessment process for Index 2 is as follows~~. If~~; if Index 2 for this Transmission Line Circuit does not trigger any of the four tests, no further action is necessary. If, however, one or more of the tests are triggered, then limits for this Transmission Line Circuit for that calendar year should be recalculated based on the historical data for this Transmission Line Circuit alone using an individual and moving range control chart. The only test warranted here is Test 1. More information on the individual and moving range control charts can be found in the user manuals of the statistical software ~~approved by the ISO for use~~used in creating the control charts

~~If the ISO deems that the Availability Measure Targets should be modified, they shall be modified in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.~~

Table ~~4.3.1~~4.2.1 Performance Indications Provided by Control Chart Tests

Control Chart Type	Test		Performance Status Indicated by Test Results	
	Number	Results	Improvement	Degradation
Annual Average Forced Outage(IMS) Frequency	1	value is above the UCL		4X
		value is below the LCL when LCL>0	4X	
	2	v1 or more consecutive values above the CL		4X
		v2 or more consecutive values below the CL	4X	
	3	2 out of 3 values above the UWL		4X
		2 out of 3 values below the LWL	4X	
	4	6 consecutive values increasing		4X
		6 consecutive values decreasing	4X	
Annual Average Accumulated Forced Outage(IMS) Duration	1	value is above the UCL		4X
		value is below the LCL when LCL>0	4X	
	2	v1 or more consecutive values above the CL		4X
		v2 or more consecutive values below the CL	4X	
	3	2 out of 3 values above the UWL		4X
		2 out of 3 values below the LWL	4X	
	4	6 consecutive values increasing		4X
		6 consecutive values decreasing	4X	
Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)	1	value is above the UCL	4X	
		value is below the LCL when LCL>0		4X
	2	v1 or more consecutive values above the CL	4X	
		v2 or more consecutive values below the CL		4X
	3	2 out of 3 values above the UWL	4X	
		2 out of 3 values below the LWL		4X
	4	6 consecutively increasing values	4X	
		6 consecutively decreasing values		4X

4.3. ~~4.4. Outage(IMS) Data Reporting~~AVAILABILITY REPORTING

~~All Outages which interrupt the flow of power on PTO Transmission Facilities under the ISO's Operational Control shall be reported by the PTO to the ISO. Outage(IMS) reports~~Each PTO shall submit an annual report to the ISO within 90 days after the end of each calendar year describing its Availability Measures performance. This annual report shall be based on Forced Outage(IMS) records. All Forced Outage(IMS) records shall be submitted by each PTO to the ISO and shall include the date, start time, end time, affected Transmission Facility, and the probable cause~~ of the Outage(IMS~~(s) if known.

5. ~~ISO MAINTENANCE GUIDELINES AND PTO~~ MAINTENANCE PRACTICES

~~5.1. Introduction~~

5.1. INTRODUCTION

~~The ISO~~These ISO Transmission Maintenance Standards, as they may be periodically revised in accordance with ~~due consideration for the recommendations of the Maintenance Coordination Committee shall establish, revise as needed, and maintain guidelines for Transmission Facilities Maintenance as described in Section 5.2 of this document. These ISO Maintenance Guidelines~~the provisions of the Transmission Control Agreement and this Appendix C, and as they may be clarified by the Maintenance Procedures, shall be followed by each PTO in preparing~~ a written description of, and updating as necessary, its PTO Maintenance Practices which may be performance-based, time-based, or both, as may be appropriate for each Transmission Facility under the ISO's Operational Control. The PTO~~, submitting, and amending its Maintenance Practices. The Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including ~~technological innovations and~~ facility importance.

~~5.2. ISO Maintenance Guidelines for Preparation of PTO Maintenance Practices~~

~~5.2.1. Transmission Line Maintenance~~

~~The PTO's Maintenance Practices shall, at a minimum, address the following transmission line Maintenance activities:~~

~~a) Patrol/Inspection~~

- ~~Routine~~
- ~~Detailed~~
- ~~Emergency~~

~~b) Vegetation Management/Right-of-Way Maintenance~~

5.2. PREPARATION OF MAINTENANCE PRACTICES

5.2.1. TRANSMISSION LINE CIRCUIT MAINTENANCE

As may be appropriate for the specific ~~facilities and equipment~~Transmission Line Circuits under the ISO's Operational Control, ~~the~~each PTO's Maintenance Practices shall ~~further detail~~describe the Maintenance activities for ~~various attributes of the transmission lines including, but not limited to:~~the various attributes listed below:

5.2.1.1. OVERHEAD TRANSMISSION LINES

- ~~Structures: wood pole, lattice steel, tubular steel, and concrete pole~~
- ~~Guys/Anchors~~
- ~~Foundations~~
- ~~Insulators~~
- ~~Conductor and Shield Wire~~
- ~~Conductor and Shield Wire Clearances~~Patrols and inspections, scheduled and unscheduled
- ~~Hardware and Fittings~~Conductor and shield wire
- Disconnects/~~Pole~~pole-top ~~Switches~~switches
-
- ~~Encroachments/Unauthorized Attachments~~
- ~~Underground Transmission Components~~Structure grounds

~~**5.2.2. Station Maintenance**~~

~~The PTO's Maintenance Practices shall, at a minimum, address the Maintenance of the following equipment and attributes of Stations:~~

- ~~Circuit Breakers~~Guys/anchors
- Insulators~~/Bushings/Arrestors~~
  - ~~Transformers~~
  - ~~Regulator~~
  - ~~Disconnect Switches~~
  - ~~Metering~~
  - ~~Battery Systems~~
  - ~~Reactive Devices~~
  - ~~Relaying~~
  - ~~Communication Facilities~~
  - ~~Station Auxiliary Equipment~~
- ~~Direct Current Transmission Components~~Rights-of-way
- Structures/Foundations
- Vegetation Management

5.2.1.2. UNDERGROUND TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Cable/Cable systems
- Cathodic Protection
- Fluid pumping facilities
- Terminations
- Arrestors
- Rights-of-way
- Splices
- Structures/vaults/manholes
- Vegetation Management

5.2.2. STATION MAINTENANCE

As may be appropriate for the specific ~~equipment in and configurations of the PTO's~~ Stations under the ISO's Operational Control, ~~the~~each PTO's Maintenance Practices shall ~~further detail various~~describe Maintenance activities for the various attributes ~~and potential conditions of the Stations including, but not limited to:~~listed below:

- Inspections, scheduled and unscheduled
- Battery systems
- Circuit breakers
- Direct Current transmission components
- ~~Visual Inspection of/for: fences and grounds, vegetation, clearances, tracking, abnormal heating, cracks/chips, noise, leaks, blown fuses, and bulging of equipment cases~~ Disconnect switches
- ~~Oil Containment~~Perimeter fences and gates
- ~~Insulation Mediums~~Station grounds
- ~~Equipment Contacts~~Insulators/bushings/arrestors
- ~~Mechanical Timing~~Reactive power components
- ~~Contamination Control~~Protective relay systems
- ~~Testing and Calibration~~Station Service equipment
- ~~Cooling Systems~~Structures/Foundations
- ~~Measuring Devices~~Transformers/regulators
- ~~Lubrication and Overhaul of Moving Parts~~Vegetation Management

~~5.2.3. Descriptions of PTO Maintenance Practices~~

5.2.3. DESCRIPTIONS OF MAINTENANCE PRACTICES

Each PTO's Maintenance Practices shall include a schedule for any time-based Maintenance activities and a description of conditions that will initiate any performance-based activities. The ~~PTO's~~ Maintenance Practices shall describe the Maintenance methods for each substantial type of component and shall provide any checklists/report forms, which may be required for the activity. Where appropriate, the ~~PTO's~~ Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility ~~or component~~. Where appropriate, the ~~PTO's~~ Maintenance Practices shall specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the Transmission ~~Facilities~~Facility.

~~5.3. Review and Adoption of PTO Maintenance Practices~~

~~5.3.1. Initial Adoption of PTO Maintenance Practices~~

~~5.3.1.1. Submittal of Information by the Prospective PTOs to the ISO~~

5.3. REVIEW AND ADOPTION OF MAINTENANCE PRACTICES

5.3.1. INITIAL ADOPTION OF MAINTENANCE PRACTICES

~~Each~~In conjunction with its application to become a PTO, each prospective PTO shall provide to the ISO ~~with information concerning~~ its ~~PTO~~proposed Maintenance Practices ~~pursuant to Section 5.2 of~~which comply with the requirements set forth in this Appendix C and Section 14.1 of the Transmission Control Agreement. This information shall ~~be prepared so as to be easily interpreted by the ISO and shall~~ provide sufficient detail for the ISO to assess the ~~adequacy and reasonableness of the PTO~~proposed Maintenance Practices~~, using the criteria referenced in Section 14.1 of the Transmission Control Agreement~~.

~~5.3.1.2. Review of the PTO Maintenance Practices by the ISO~~

The ISO shall review the ~~information provided pursuant to Section 5.3.1.1 of this Appendix C and may provide to a PTO a recommendation for an amendment to the PTO Maintenance Practices in question by means of a notice delivered in accordance with Section 26.1 of~~proposed Maintenance Practices and may provide recommendations for an amendment. To the extent there is any disagreement between the ISO and the prospective PTO regarding the prospective PTO's proposed Maintenance Practices, such disagreement shall be resolved by the ISO and prospective PTO so that the ISO and the prospective PTO will have adopted Maintenance Practices, consistent with the requirements of this Appendix C and the Transmission Control Agreement~~. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C~~, for the prospective PTO at the time that the ISO assumes Operational Control of the prospective PTO's Transmission Facilities. To the extent there are no recommendations, the ~~PTO~~proposed Maintenance Practices will be adopted by the ISO~~, pursuant to California Public Utilities Code Section 348, as the PTO~~ and the prospective PTO as the Maintenance Practices for that prospective PTO.

~~Any agreement, in respect of PTO Maintenance Practices, reached between the ISO and a prospective PTO prior to the ISO Operations Date shall be adopted by the ISO for purposes of this Section 5.3.1.~~

~~5.3.2. Proposals for Amendments to the PTO Maintenance Practices~~

5.3.2. AMENDMENTS TO THE MAINTENANCE PRACTICES

5.3.2.1. ~~Amendments Proposed~~AMENDMENTS PROPOSED BY THE ISO

Each PTO shall have in place Maintenance Practices that have been adopted by the ISO as set forth in this Appendix C. The ISO shall periodically review each PTO's Maintenance Practices having regard to ~~the~~these ISO Transmission Maintenance Standards~~, as amended and revised from time to time pursuant to Sections 7 and 8 of this Appendix C~~ and Maintenance Procedures. Following such a review, ~~and after considering the Section 348 Criteria,~~ the ISO may recommend an amendment ~~of~~to any PTO's Maintenance Practices~~,~~ by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The ~~disposition of any such~~PTO may draft amended language in response to the ISO's recommendation ~~shall be in accordance with 5.3.3 of this Appendix C. Except as provided in Section 5.3.3.4 of this Appendix, the effective date shall be no earlier than 30 days from the date~~. If the PTO exercises its option to draft amended language to the ISO's proposed amendment, the PTO shall so notify the ISO within 30 days after the receipt of ~~such notice.~~notice from the ISO. The PTO will provide the ISO with its proposed amendment language in a time frame mutually agreed upon between the PTO and the ISO. If, after the ISO receives the proposed amendment language from the PTO, the ISO and the PTO are unable to agree on the language implementing the ISO recommendation, then the provisions of Section 5.3.3.2 of this Appendix C shall apply.

5.3.2.2. ~~Amendments Proposed by a PTO~~AMENDMENTS PROPOSED BY A PTO

Each PTO may provide to the ISO its own recommendation for an amendment to its ~~PTO~~own Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. ~~The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. The effective date shall be no earlier than 30 days from the date of such notice.~~

~~5.3.3. Disposition of Recommendations~~

5.3.3. DISPOSITION OF RECOMMENDATIONS

5.3.3.1. If the ISO ~~or a PTO~~ makes a recommendation to amend the ~~PTO~~ Maintenance Practices of a PTO, as contemplated in ~~Sections 5.3.1 or 5.3.2~~Section 5.3.2.1 of this Appendix C, ~~the other Party~~that PTO shall have 30 ~~days~~Business Days to provide a notice to the ~~recommending party~~ISO, pursuant to Section 26.1 of the Transmission Control Agreement, stating that it does not agree with the recommended amendment~~. If it fails to provide such notice of disagreement, the~~ or that it intends to draft the language implementing the amendment, as set forth in Section 5.3.2.1 of this Appendix C. If the PTO does not provide such a notice, the amendment recommended ~~amendment shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified in the notice of the recommended amendment, which date shall be no earlier than 30 days from the date of issuance of such notice of amendment~~by the ISO shall be deemed adopted.

If a PTO makes a recommendation to amend its own Maintenance Practices, as contemplated in Section 5.3.2.2 of this Appendix C, the ISO shall have 30 Business Days to provide a notice to that PTO, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not concur with the recommended amendment. If the

ISO does not provide such a notice, then the recommended amendment shall be deemed adopted. Notwithstanding the foregoing, if an amendment proposed by a PTO to its own Maintenance Practices meets the objectives of Section 2.1 of this Appendix C and is submitted in accordance with the requirements in Section 5.2 of this Appendix C, the ISO shall adopt said amendment.

If any amendment to a PTO's Maintenance Practices is adopted, the PTO will specify the transition time to implement the adopted amendment so as to ensure the ISO and PTO are clear as to the implementation time frame where Maintenance may be performed under both sets of practices.

5.3.3.2. If the ISO or a PTO makes a recommendation to amend ~~its PTO~~ Maintenance Practices~~,~~ and if the ISO or PTO provides notice within the 30 ~~days specified in the first paragraph of this Section 5.3.3, pursuant to Section 26.1 of the Transmission Control Agreement, that the ISO, having regard for the Section 348 Criteria,~~Business Days specified in Section 5.3.3.1 of this Appendix C that the ISO or PTO does not agree with the recommended amendment, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If, after such efforts, the PTO and the ISO cannot reach a resolution, the pre-existing ~~PTO~~ Maintenance Practices shall ~~be retained.~~remain in effect. Either Party may, however, seek further redress through appropriate processes, including ~~the Maintenance Coordination Committee, the ISO Governing Board, and/or~~ non-binding discussions at the TMCC and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. ~~Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.~~~~**5.3.3.3.** If the ISO makes a recommendation to amend the PTO Maintenance Practices of a PTO, the PTO Maintenance Practices, as amended pursuant to the ISO recommendation, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified by the ISO in its notice of recommended amendment. If the PTO gives notice of a~~

~~disagreement within the 30 days specified in the first paragraph of this Section 5.3.3, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If a resolution is not reached, either Party may seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement.~~ The PTO may also request, during the initial attempts at resolution and at any stage of the redress processes, a deferral of the ISO recommended amendment~~,~~ and the ISO shall not unreasonably withhold its consent to such a request~~, having regard to the Section 348 Criteria~~. Following the conclusion of ~~the~~any and all redress processes, the PTO's Maintenance Practices, as ~~altered~~modified, if at all, by these processes, shall be deemed adopted by the ISO, ~~pursuant to California Public Utilities Code Section 348, as the PTO~~as the Maintenance Practices for that PTO, pursuant to the implementation time frame agreed to between the PTO and the ISO.

~~5.3.3.4.~~ 5.3.3.3. If the ISO determines~~ in its judgment, after considering the Section 348 Criteria~~, that prompt action is required to avoid a substantial risk to ~~safety or~~ reliability of the ISO Controlled Grid, it may direct a PTO to implement certain temporary ~~maintenance~~Maintenance activities in a period of less than 30 ~~days~~Business Days, by issuing an advisory to the PTO to that effect, by way of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. Any ~~such maintenance practice advisories~~advisory issued pursuant to this Section 5.3.3.3 shall specify why implementation solely under ~~Section 5.3.3.3~~Sections 5.3.3.1 and 5.3.3.2 of this Appendix C is not sufficient to avoid a substantial risk to ~~safety or~~ reliability of the ISO Controlled Grid, including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. ~~If time permits, the~~The ISO shall consult with the relevant PTO before issuing a ~~maintenance practice~~Maintenance advisory. Upon receiving such an advisory, a PTO shall implement the temporary ~~maintenance~~Maintenance activities in question, as of the date specified by the ISO in its advisory, unless the PTO provides a notice to the ISO, in accordance with Section 26.1 of the Transmission Control Agreement, that the PTO is unable to implement the temporary ~~maintenance~~Maintenance activities as specified. Even if the PTO provides such a notice, the PTO shall use its best efforts to implement the temporary ~~maintenance~~Maintenance activities as fully as possible. All ~~such maintenance practice~~Maintenance advisories shall cease to have effect ~~in~~ 90 ~~days~~Business Days after issuance ~~or~~by the ISO or on such earlier ~~period~~date as the ISO provides in its notice. ~~Renewal or extension of such temporary maintenance requirements beyond 90 days~~ Any Maintenance advisories required to remain in effect beyond 90 Business Days shall require a recommendation process pursuant to Section ~~5.3.3.2~~5.3.3.1 or Section ~~5.3.3.3~~5.3.3.2 of this Appendix C.

~~**5.3.3.5.** Nothing in this Transmission Control Agreement shall be construed to limit the ISO's authority under Public Utilities Code Section 348 to adopt inspection, maintenance, repair, and replacement standards for the transmission facilities under ISO control.~~

~~5.4. Qualifications of Personnel~~

5.4. QUALIFICATIONS OF PERSONNEL

All Maintenance of Transmission Facilities ~~under the ISO's Operational Control~~ shall be performed by persons who, by reason of training, experience and instruction, are qualified to perform the task.

6. MAINTENANCE RECORD KEEPING AND REPORTING

~~The four elements of the ISO's requirements for Maintenance record keeping and reporting are as follows:~~

~~a)~~ ~~The~~A PTO ~~will~~shall maintain and provide to the ISO records of its Maintenance activities~~, as set forth~~ in accordance with this Section ~~6.1.~~6 of this Appendix C.

~~b) The PTO will provide certain Maintenance records to the ISO, as set forth in Section 6.2.~~

~~c) The PTO will allow the ISO to visit Transmission Facilities, as set forth in Section~~

~~6.3.~~

~~d) The PTO will make records for Maintenance activities available to the ISO, as set forth in Section 6.4.~~

~~In addition, the Maintenance Coordination Committee shall annually review the requirements of this section of the ISO Maintenance Standards and shall seek to standardize reasonable record keeping, reporting and information-sharing requirements sufficient to support ISO regulatory reporting needs.~~

~~6.1. The PTO Will Maintain Records of its Maintenance Activities~~

6.1. PTO MAINTENANCE RECORD KEEPING

The ~~PTO shall maintain records demonstrating compliance with each element of the PTO~~minimum record retention period for Transmission Facilities subject to time based scheduled intervals shall be the designated Maintenance ~~Practices. The PTO's Maintenance records shall be maintained for five years, or for one year after specific corrective~~cycle plus two years. The minimum record retention period for all other Transmission Facility Maintenance activities identified ~~by the PTO are completed, whichever is longer~~through inspection, assessment, diagnostic or another process shall be a minimum of 2 years after the date completed.

~~Each~~A PTO's ~~inspection~~Maintenance records shall, at a minimum, ~~identify the inspector, the Transmission Facility inspected, the inspection date(s), the findings of the inspection, recommended Maintenance activities, and the priority of the Maintenance recommendations. Each PTO's Maintenance records shall, at a minimum, identify the person responsible for performing the Maintenance, the date of the Maintenance, the Transmission Facility maintained, and a description of the Maintenance that was~~include the: 1) responsible person; 2) Maintenance date; 3) Transmission Facility; 4) findings (if any); 5) priority rating (if any); and 6) description of Maintenance activity performed.

~~6.2. The PTO Will Provide Certain Maintenance Records to the ISO~~

~~By the end of the third year of operation of the ISO, the ISO and PTO's shall develop and implement a standard Maintenance reporting system based on the recommendations of the Maintenance Coordination Committee. Until the standard Maintenance reporting system is implemented, the PTO shall provide the ISO, on an annual basis, records for substantial Maintenance as limited by the following list:~~

6.2. PTO MAINTENANCE REPORTING

~~**a) Transmission Line Maintenance**~~Each PTO will submit a Standardized Maintenance Report as outlined in the Maintenance Procedures. The ISO will accept, at the PTO's option, a Standardized Maintenance Report in either electronic or paper form.

- ~~Patrol/Inspection~~
- ~~Vegetation Management/Right-of-way Maintenance~~
- ~~Structures: Wood pole, lattice steel, tubular steel, concrete pole~~
- ~~Insulators (Contamination Control)~~

~~**b) Station Maintenance**~~

- ~~Circuit Breakers~~
- ~~Transformers~~
- ~~Insulators/Bushings/Arrestors (Contamination Control)~~
- ~~Regulators~~
- ~~Relaying~~

If ~~the~~a PTO ~~maintains~~retains records in a manner that includes additional information, such records may be submitted in that manner.

~~6.3. The PTO Will Allow the ISO to Visit Transmission Facilities~~

Each PTO shall provide to the ISO Maintenance records as described in Section 6.1 and as set forth in the Maintenance Procedures.

6.3. ISO VISIT TO PTO'S TRANSMISSION FACILITIES

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement~~.~~ to determine if the Maintenance Practices are being followed by a PTO.

~~6.4. The PTO Will Make Records for Maintenance Activities Available to the ISO~~

~~The PTO shall make all Maintenance records for a Voltage Class available to the ISO upon the request of the ISO if the annual evaluation of performance per Section 4.3.3 demonstrates degradation in the PTO's Availability performance. Upon identification of degradation, the PTO's reporting of Maintenance data to the ISO shall continue until a subsequent year's annual performance returns to a non-degraded level.~~

~~If a review of available records by the ISO indicates inconsistencies from the PTO Maintenance Practices relating to a specific activity, then the ISO may request that the PTO provide further documentation and explanation related to those Maintenance activities.~~

7. ISO AND TRANSMISSION MAINTENANCE COORDINATION COMMITTEE

~~7.1. Maintenance Coordination Committee Functions~~

The ISO shall ~~seek to~~ establish and ~~then appropriately~~ convene a Transmission Maintenance Coordination Committee ~~for the purposes of periodically~~(TMCC). The TMCC shall develop and, if necessary, revise the Maintenance Procedures, including conveying information~~,~~ to and seeking input from ~~other~~ PTOs and other interested stakeholders regarding ~~ISO Maintenance Standards as well as making recommendations with respect to proposed amendments and revisions of the ISO~~

~~Maintenance Standards.~~these Maintenance Procedures and any proposed amendments or revision thereto. The TMCC will also make recommendations on the ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will convey information to and seek input from the PTOs and other interested stakeholders on these ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will also perform any other functions assigned in this Appendix C.

~~7.2. Consensus~~

Although the role of the Transmission Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members~~, and promulgate practices, standards and protocols consistent with relevant laws and regulations~~.

8. REVISION OF ISO TRANSMISSION MAINTENANCE STANDARDS AND MAINTENANCE PROCEDURES

8.1 REVISIONS TO ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO, ~~PTO's~~PTOs, or any interested stakeholder may submit proposals to amend or revise ~~the~~these ISO Transmission Maintenance Standards. ~~Any change proposal~~All proposals shall be initially submitted to the ~~Maintenance Coordination Committee for consideration~~TMCC for review in accordance with ~~Section 7.0, "Maintenance Coordination Committee," of this document. Recommendations for~~this Appendix C. Any revisions ~~of the~~to these ISO Transmission Maintenance Standards shall be ~~submitted by the Maintenance Coordination Committee to the ISO for approval~~made only upon recommendation by the TMCC and only in accordance with the provisions and requirements of the Transmission Control Agreement and this Appendix C.

8.2 REVISIONS TO AND DEVIATIONS FROM MAINTENANCE PROCEDURES

The ISO or any PTO may submit proposals to the TMCC to amend or revise the Maintenance Procedures. Any deviations from the Maintenance Procedures should be held to a minimum and will be negotiated between the ISO and the affected PTO.

9. ~~9.~~ INCENTIVES AND PENALTIES

9.1 DEVELOPMENT OF A FORMAL PROGRAM

The TMCC shall periodically investigate and report to the ISO on the appropriateness of a formal program of incentives and penalties associated with Availability Measures. Should the TMCC ever recommend that the ISO adopt a formal program of incentive and penalties, the formal program will only be adopted as set forth in Section 9.2 of this Appendix C.

9.2 ADOPTION OF A FORMAL PROGRAM

Any formal program of incentives and penalties ~~relating to~~adopted by the ISO in connection with matters covered in Section 14 of the Transmission Control Agreement or this Appendix C, shall be established only: 1) with respect to Availability Measures; 2) upon recommendation of the TMCC as set forth in Section 9.1 of this Appendix C; 3) by express incorporation into this Appendix C in accordance with the provisions of the Transmission Control Agreement~~, the ISO Tariff and ISO Protocols after consultation between the PTO and the ISO, and approval by the FERC. No incentives, penalties or sanctions may be imposed relating to this Appendix unless a Schedule providing for such incentives, penalties or sanctions has first been filed with and made effective by the FERC.~~ ; and 4) upon approval by the FERC. Nothing in this Appendix C shall be construed as waiving or limiting in any way the right of any party or PTO to oppose or protest any formal program of incentives and penalties filed, proposed or adopted by the ISO and/or FERC or any portion thereof.

9.3 IMPOSITION OF PENALTIES IN THE ABSENCE OF A FORMAL PROGRAM

In the absence of a formal program of incentives and penalties, the ISO may seek FERC permission for the imposition of specific penalties on a PTO on a case-by-case basis in the event that the relevant PTO 1) exhibits significant degradation trends in Availability performance due to Maintenance, or 2) is grossly or willfully negligent with regard to Maintenance.

9.4 NO WAIVER

Nothing in this Appendix C shall be construed as waiving the rights of ~~the~~any PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC, the approval by FERC of any specific penalty or sanction, or the specific imposition by the ISO of any FERC- approved penalty or sanction on the PTO.

9.5 LIMITATIONS ON APPLICABILITY TO NEW PTOS

For a new PTO, the Availability Measures system needs to be used and updated during a five calendar year phase in period, as set forth in Section 4.2 of this Appendix C, to be considered in connection with any formal program of incentives and penalties associated with Availability Measures.

10. ~~10.~~ COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain ~~its~~and the ISO shall operate Transmission Facilities ~~that are under the Operational Control of the ISO~~ in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable ~~protocols,~~ laws~~,~~ and regulations~~, in order to achieve the Availability Measure Targets set by the ISO~~.

10.1 SAFETY

~~It is of paramount importance that the~~Each PTO shall take proper care to ensure the safety of personnel~~,~~ and the public in performing ~~these~~ Maintenance duties~~ and that the~~. The ISO shall operate ~~the system~~Transmission Facilities in a manner ~~which is~~ compatible with the priority of ~~ensuring safety. The PTO shall ensure the safety of personnel and the public in accordance with jurisdictional agency regulations and ensure the reliability of the system in accordance with CAISO Maintenance Standards.~~safety. In the event there is conflict between ~~the~~ safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. ~~11.~~ DISPUTE RESOLUTION

Any ~~disputes~~dispute between the ISO and a PTO ~~regarding issues related to the Maintenance, and Availability of Transmission Facilities under the Operational Control of the ISO shall be resolved in accordance with the Section 15~~relating to matters covered in this Appendix C shall be subject to the provisions of the Transmission Control Agreement~~.~~, including the dispute resolution provisions set forth therein.

SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

~~Revised September 2, 2002~~

Revised as of October 10, 2006

I. OVERVIEW

The preferred source of electrical power for the San Onofre Nuclear Generating Station (SONGS) electrical loads (safety-related and ~~nonsafety~~ non-safety-related) is the ***offsite power supply*** or 230 kV grid. The offsite power supply is sometimes referred to as the ***preferred power supply*** in the applicable regulatory documents.

The ~~basic requirement for the~~ offsite power supply is ~~that~~ considered "Operable" with respect to the SONGS Operating License and Technical Specifications when it ~~provides~~ can provide sufficient capacity and capability to supply electrical loads needed to safely shut down the reactor and ~~to~~ mitigate certain specified accident scenarios. ~~When this condition is met, the~~

The offsite power supply is considered ~~Operable~~ "Inoperable" with respect to the SONGS Operating License and Technical Specifications~~.~~ if it is degraded to the point that it cannot provide sufficient capacity and capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS.

It is a necessary condition of the SONGS Operating License and Technical Specifications that the offsite power supply be Operable at all times. If the offsite power ~~system~~ supply is declared Inoperable, action must be taken to shut down an online SONGS unit(s) and, for an offline unit, to suspend activities as required by the SONGS Operating License and Technical Specifications. ~~The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS.~~

~~This~~The level of degradation that would result in inoperability can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable to safely shutdown the units or to supply emergency electrical loads.

~~In specific terms, the offsite power supply voltage (at the SONGS switchyard) must stay within the range of 218 kV to 238 kV under all normal and plant accident (i.e. emergency shutdown or trip) conditions. Otherwise the offsite power supply is considered Inoperable.~~

Since accident scenarios for which the SONGS plant is designed can result in a unit trip, it is imperative that ~~the~~ this trip not impair the operability of the offsite power ~~system. Therefore, following a trip of a SONGS unit (i.e., the unit breakers open), the~~

~~SONGS switchyard voltage must recover to and be maintained at or above 218 kV within 2.5 seconds following the trip. If this condition cannot be met, then the offsite power supply is considered Inoperable, and action must be taken to shut down the operating SONGS unit(s). Even though these requirements apply at all times, this condition is primarily of concern when one SONGS unit is online and the other unit offline~~supply. If both SONGS units are online and one unit trips (due to an accident or otherwise), the non-tripped unit will provide local voltage support to the SONGS switchyard, and 230 kV system voltage will remain within the required range. In cases where one SONGS unit is online and one unit offline, the offsite power supply must be sufficiently robust to survive a trip of the online unit and meet the SONGS voltage requirements in the post-trip condition. A dual unit trip is not the limiting condition since a plant accident is not postulated simultaneous with a dual unit trip.

System Operating ~~p~~Procedures (see Reference 9 below) and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and communicated to the SONGS Control Room ~~for Operability determination~~.

The SONGS switchyard is made up of the Southern California Edison Company (SCE) switchyard and the San Diego Gas & Electric Company (SDG&E) switchyard. Unless specifically stated otherwise, SONGS switchyard requirements contained in this document apply to both the SCE switchyard and the SDG&E switchyard.

~~SPECIFIC~~II. REQUIREMENTS

Note ~~1:~~ : This section identifies the operational requirements for the SONGS offsite power supply. These requirements are part of the SONGS design basis and licensing basis. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating SONGS unit(s) to shutdown. Failure to meet these requirements must be ~~immediately~~ communicated to SCE and the SONGS Control Room for operability determination~~.~~ as soon as practicable, but in any case, within one hour. Changes in the operation of the transmission network that conflict with these requirements ~~require~~ must have prior approval by SCE.

Note ~~2:~~ : Specific requirements, procedures, operating bulletins, division orders, and analysis that support or provide the basis for the specific operational requirements may be revised periodically subject to prior approval of the affected parties.

1. Nine transmission lines into the SONGS switchyard are normally in service.- Any increase or decrease in the number of lines into the SONGS switchyard requires prior approval -of SCE.- (Reference 7 below)

   ———No line may be removed from service for greater than 30 days without prior notification to SCE. -At least two independent transmission lines (one from

SCE and one from SDG&E) between the transmission network (grid) and SONGS switchyard shall be in service at all times. (References 1, 2, 3, 4, 7, 8 below)

2. With both San Onofre units off-line, the SONGS offsite power source shall be capable of providing 158 MW and 96 MVAR to ~~San Onofre~~ SONGS for normal operation and for shutting down the units during plant Design Basis Accident (DBA) conditions.- (References 9, 10 below)

3. The minimum grid voltage at the SONGS switchyard shall be maintained at or above 218 kV.- In the event of a system disturbance that can cause the voltage to dip below 218 kV, including the trip of a SONGS unit, the grid voltage shall recover to 218 kV or above within 2.5 seconds.- (References 9, 10, 12, 13, 18 below)

4. The following initiating events shall not result in the loss of grid stability or availability:

   a. ~~a.~~ The loss of a ~~San Onofre~~ SONGS Unit (with the other unit already offline), or

   b. The loss of any generating unit on the SCE and SDG&E grids, or

   c. The loss of any major transmission circuit or intertie on the SCE and SDG&E grids, or

   d. The loss of any large load or block of load (e.g., due to a bus section outage) on the SCE and SDG&E grids.

   (References 2, 3, 4, 8 below)

5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below ~~238~~ 234 kV.- (References 10, 11, 18 below)

6. The normal operating voltage of the SONGS switchyard shall be maintained at ~~230~~229 kV.- The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. -(References 10, 11, 18 below)

7. The 3 limiting conditions for SONGS offsite power ~~source~~ supply operability are defined as follows:

   1. One SONGS unit is off- line, and
   2. One of the critical line (s) outages, in GCC Operating Procedure, OP-13: SONGS Voltage (reference 19) occurs ~~(see list of the lines below)~~, and

3. VAR flows north and south of SONGS are above the threshold levels for the existing combined SCE and SDG&E import level as defined by the nomograms referenced ~~nomograms~~ in the GCC Operating Procedure~~-~~, OP-13: SONGS Voltage ~~(Current revision)~~.

~~Based on these nomograms and SONGS offline unit's status, if the Grid Control Center or ISO determines that the operating point is outside the applicable derated nomogram line, they shall notify SONGS immediately that a particular transmission line is out of service, and the critical system conditions are sufficient to cause SONGS off site power source to be considered INOPERABLE; i.e., unable to support SONGS voltage at 218 kV if the remaining unit trips.~~

Based on these nomograms and SONGS offline unit's status, whenever limiting conditions 1 and 2, as set forth in this Requirement 7, occur, the ISO (or the SCE Grid Control Center (SCE GCC), as directed by the ISO) shall, as soon as practicable but, in any case, within one hour of the event, perform an evaluation of system conditions to determine whether or not the SONGS offsite power supply remains Operable as defined herein. If the SONGS offsite power supply is Inoperable or cannot be determined to be Operable as defined herein, the ISO (or the SCE GCC, as directed by the ISO) shall notify the SONGS Control Room immediately of entry into the event. Subsequent to notification, SONGS Control Room ~~will~~ shall declare the offsite ~~source inoperable~~power supply Inoperable (in anticipation of losing the second SONGS unit) and ~~will~~ shall declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected.~~-~~ The time period ~~will~~shall be within 1 to 24 hours, based on the SONGS plant and equipment conditions.

~~List of critical transmission lines/grid conditions:~~

~~Critical Line(s) Out In SCE Territory~~

~~Palo Verde -Devers 500 kV Line~~
~~Ellis- Johanna & Ellis-Santiago 230 kV Lines~~
~~Lugo-Serrano & Mira Loma-Serrano 500 kV Lines~~
~~Lugo- Mira Loma 2&3 500 kV Lines~~
~~Two Midway - Vincent 500 kV Lines~~
~~SONGS- Serrano & SONGS - Chino 230 kV Lines~~

~~Critical Line(s) Out in SDG&E Territory~~

~~Hassayampa-N. Gila 500 kV Line~~
~~N. Gila- Imperial Valley 500 kV Line~~
~~Imperial Valley- Miguel 500 kV Line~~
~~Imperial Valley- Miguel 500 kV Line & Imperial Valley- LaRosita 230 kV Line~~
~~SONGS-San Luis Rey 230 kV Tap & SONGS - Mission 230 kV Line~~

~~Critical Grid Conditions:~~

~~SCE/SDG&E Tie Separation at SONGS:~~

~~SCE/SDG&E Tie Open, Unit 3 On-Line (Unit 2 Off-Line)~~
~~SCE/SDG&E Tie Open, Unit 2 On-Line (Unit 3 Off-Line)~~

In order to ensure the continued ability to meet the 3 limiting conditions identified above in this Requirement 7, the following six requirements (a-f) must be met:

a. Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions~~, such as the above cases,~~ that could render the offsite power supply Inoperable. ~~The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to provide electrical support to safe shutdown loads and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. The following actions are required:~~

~~a.~~b. Procedures and programs shall be in effect to ensure that the SONGS Control Room is ~~immediately~~ notified as soon as practicable but, in any case, within one hour of ~~such conditions.~~ an event that renders the offsite power supply Inoperable.

~~b.~~c. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, shall render the offsite power supply Inoperable. ~~The SONGS Control Room shall be immediately notified of such conditions.~~

~~c.~~d. Auditable records of current system studies shall be made available to SCE as needed to demonstrate compliance with regulatory requirements. Study results, including revisions and updates, shall be formally transmitted to SCE.

~~d.~~e. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be formally transmitted to ~~SCE.~~ Vice President Nuclear Engineering and Technical Services, San Onofre Nuclear Generating Station. (References 1, 2, 19, and 21 below)

f. System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the Western Electricity Coordinating Council (WECC). (Reference 7 below)

8. ~~8.~~ In the event of loss of the SONGS offsite power ~~supply~~:

Note: SONGS 2 and 3 are required by NRC regulations to be able to safely cope with a loss of all AC power (Station Blackout) for a maximum of four hours.- The four hour coping duration is based on the expectation that at least one source of AC power (offsite transmission line or onsite diesel generator) will be restored to the blacked-out unit within the four hours to ensure the proper functioning of systems required for plant safety.

a. Highest possible priority shall be given to restoring power to the SONGS switchyard. -Procedures and training should consider several potential methods of transmitting power from black-start capable units to the SONGS switchyard. –This includes such items as nearby gas turbine generators, portable generators, hydro generators, and black-start fossil power plants. -(References 15, 26, 28 below)

b. Should incoming lines to the SONGS switchyard be damaged, highest priority shall be assigned to repair and restoration of at least one line into the SONGS switchyard.

c._ Repair crews engaging in power restoration activities for SONGS shall be given the highest priority for manpower, equipment, and materials.

d._ Formal programs and procedures shall be in place to effect items a, b~~,~~ and c above.

_(References 14, 15, 16, 17, 26, 27 below)

9._ Grid frequency shall be maintained at 60 Hertz (nominal).- A trip of one SONGS unit shall not cause the grid frequency to dip below 59.7 Hertz. -SCE and SDG&E shall comply with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

~~**Note: System separation between SCE and SDG&E at the SONGS bus tie on low grid frequency mentioned in the previous version of the TCA is being removed from SONGS by mid-2002. Increased load shedding schemes by SDG&E have been implemented which preclude the need for system separation at SONGS bus ties on low frequency.**~~

_(References 7, 20 below)

10._ SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS ~~2&3~~ Updated Final Safety Analysis Report (UFSAR) shall be maintained.- It is recognized that the SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report may be revised from time to time. In the event the reliability criteria are revised, a system assessment and/or study (as described under specification 7) shall be performed to determine if the revised reliability criteria adversely impact grid reliability and availability as defined in this specification. -Results of the assessment and/or study together with a copy of the revised reliability criteria shall be provided to SCE. -Changes in grid operation based on the revised criteria and associated studies shall not be implemented without prior approval of SCE. (Reference 7 below)

11._ Patrol and inspection of SCE and SDG&E transmission lines, to ensure that the physical and electrical integrity of transmission components are maintained, shall be performed as required by the SONGS UFSAR or in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice ~~or as required by the NRC plant operating license~~, whichever requirement is more stringent. ~~These patrols and inspections are to ensure that the physical and electrical integrity of transmission system components are maintained.~~ (Reference 7 below)

12._ Line insulators on lines which carry power from the plant to the grid shall be washed as required by the ~~NRC plant operating license~~SONGS UFSAR or on an appropriate wash cycle in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent.- The purpose and frequency of which is proven to prevent line outages that may result from flashovers due to accumulated contamination. -(Reference 7 below)

13._ Maintenance, testing and calibration of SCE and SDG&E station equipment and protective relays shall be performed as required by the SONGS UFSAR or in accordance with the current ISO approved Electrical Station Maintenance Practice ~~or as required by the NRC plant operating license~~, whichever requirement is more stringent.- (Reference 7 below)

14._ Preventive maintenance and testing of SONGS switchyard batteries shall be performed ~~per~~ in accordance with IEEE 450-~~1972~~-1985 or IEEE 450-2002 subsequent to SONGS converting its battery maintenance program to IEEE 450-2002 requirements. ~~Preventive maintenance and testing of SONGS switchyard battery chargers and DC system components shall be performed routinely.~~ (Reference 7, 23 below)

15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS ~~2 & 3 Updated Final Safety Analysis Report (~~UFSAR~~)~~ shall be provided annually~~. These updates will be used by SCE to prepare a UFSAR change submittal to the NRC. SONGS is required by 10CFR50.71(e) to submit to the NRC~~ to facilitate periodic updates to the UFSAR by SONGS that are required by 10CFR50.71(e).

III REFERENCES (Current approved revision except as noted)

1)_ SONGS 2&3 Operating License and Technical Specifications, Section 3.8, Electrical Power Systems

2)_ 10CFR50 Appendix A, General Design Criterion 17 (GDC-17), Electrical Power Systems

3)_ NUREG 75/087, Standard Review Plan Revision 1, Section 8.2, Offsite Power System

4)_ NUREG 0800, Standard Review Plan Revision 2, Section 8.2, Offsite Power System

5)_ NUREG 0800, Standard Review Plan Revision 2, Branch Technical Position ICSB-11 (PSB), Stability of Offsite Power Systems

6)_ NUREG 0712, SONGS 2&3 Safety Evaluation Report, Section 8.0, Electric Power Systems

7)_ SONGS 2 & 3 Updated Final Safety Analysis Report, Section 8.0, Electric Power

8)_ ANSI/IEEE Std. 765~~-1983~~-2002 Preferred Power Supply for Nuclear Power Generating Stations

9)_ SONGS Design Calculation E4C-082, System Dynamic Voltages During Design Basis Accident

10)_ SONGS Design Calculation E4C-090, Auxiliary System Voltage Regulation

11)_ SONGS Design Calculation E4C-092, Short Circuit Studies

12)_ SONGS Design Calculation E4C-098, 4 kV Swgr Protective Relay Setting

13)_ DBD-SO23-120, SONGS Design Basis Document, 6.9KV, 4.16KV and 480V Electrical Systems

14)_ 90051, SONGS Station Blackout Analyses

15)_ NUMARC 87-00 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors

16)_ Letter from M. 0. Medford (SCE) to the Document Control Desk (NRC), dated April 17, 1989, Subject: "Response to 10 CFR 50.63, `Loss of all Alternating Current Power,' San Onofre Nuclear Generating Station Units 1, 2 and 3"

17)_ Letter from F. R. Nandy (SCE) to the Document Control Desk (NRC), dated May 1, 1990, Subject: "Supplemental Response to 10 CFR 50.63, 'Loss of All Alternating Current Power,' Station Blackout (TAC No. 68599/600), San Onofre Nuclear Generating Station Units 1, 2, and 3"

18)_ System Operating Bulletin 17 Appendix, System Voltage Control for San Onofre Nuclear Generating Station ~~(Current approved revision)~~

19) GCC Operating Procedure~~:~~ , OP-013: SONGS Voltage ~~(Current approved revision)~~

20) System Operating Bulletin 113, San Onofre 220 kV System Separation ~~(Current approved revision)~~

21) Regulatory Guide 1.93, Revision 0, Availability of Electric Power Sources

23) SCE Division Order 60.20, Storage Batteries ~~(Current approved revision)~~

26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration ~~(Current approved revision)~~

27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV ~~(Current approved revision)~~

28) - SDG&E Control Procedure 1150, Capacity & Energy Emergencies - SDG&E System Emergencies ~~(Current approved revision)~~

29) IEEE Std. 450-1985 IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations

30) IEEE Std. 450-2002 IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications

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Trans-Elect NTD Path 15, LLC

Name of Primary
Representative: Robert ~~L. Mitchell~~ D. Dickerson

Title: Executive Vice President & Chief Operating Officer

Trans-Elect NTD Path 15, LLC

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Title: ~~Senior~~ Vice President – Acquisitions, Rates & Regulation

Trans-Elect, Inc.

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* * *

Trans Bay Cable LLC

Name of Primary	
Representative:	David Parquet
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Fax No:	415-267-1500

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the entities that are to receive service as described in that document, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 11th day of August, 2006.

John Anders BKM

John Anders