California ISO
Shaping a Renewed Future

California Independent
System Operator Corporation

March 15, 2011

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

Re: California Independent System Operator Corporation
Docket No. ER11-2295-000
Compliance Filing

Dear Secretary Bose:

The California Independent System Operator Corporation submits this filing in compliance with the Commission's February 14, 2011 letter order in the above-referenced docket. In this order, the Commission accepted the ISO's December 3, 2010 revisions to its Transmission Control Agreement (TCA) to reflect that it assumed operational control of Trans Bay Cable, LLC's transmission rights and requested that the ISO refile several records containing tables that were misaligned and not legible.

The ISO has revised the records in the TCA to correct the formatting of the tables that were misaligned and not legible and is refiling the corrected records herewith. In addition, the ISO is refilling three additional records of the TCA in order to adjust the record collation value of those records. The clean sheets of the reformatted tables and re-collated records being refiled are set forth in Attachment A.

The ISO respectfully requests that the Commission accept this filing as complying with the directives of the Commission's February 14, 2011 order.

Respectfully submitted,

By: *<u>/s/ Michael D. Dozier</u>*

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Attachment A – Clean TCA Records

California Independent System Operator Corporation

Transmission Control Agreement Compliance Filing

ER11-2295-000

March 15, 2011

TRANSMISSION CONTROL AGREEMENT

Among
The Independent System Operator
and
Transmission Owners

Tariff Record Proposed Effective Date: 11/23/10
Version Number: 1.0.0
Option Code: A

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

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	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.
.	City-Edison Pacific Intertie D-C Transmission Facilities Agreement	LADWP	48	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).
.	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.
.	Los Angeles-Edison Exchange Agreement	LADWP	19	May 31, 2025	• 500 MW of bi-directional firm entitlement on the PDCI transmission line.
.	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	74	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	09	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	24	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.
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.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
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.

Supplement to Edison Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), Southern California Edison Company (Edison) is providing notice its transmission system[1] being placed under the California Independent System Operator's (ISO) Operational Control will meet the Applicable Reliability Criteria in 1998,[2] except as noted in its bulk power program and described herein. Edison's transmission system has been developed in accordance with NERC and WSCC's reliability criteria. WSCC's most recent Log of System Performance Recommendations, dated April 15, 1997, does not show any instances where Edison's transmission system does not meet NERC and WSCC reliability criteria, absent approved exemptions.

Pursuant to Section 4.1.5 (i), Edison does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of Edison's utility service pursuant to AB 1890. However, Edison can't warrant that these right of way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from Edison's rights pursuant to its physical ownership and operation of transmission facilities.

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[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Edison's most recent assessment is based on Edison's substation and system load forecasts for study year 1998 and criteria in effect as of September 1, 1997. Edison meets WSCC's reliability criteria except for WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high. Assessments of Edison's transmission system using NERC Planning Standards and Guides, released September 16, 1997 will be performed in accordance with the ISO's coordinated transmission planning process as provided for in the ISO Tariff, Section 3.2.2. and under schedules adopted in that process.

Modification of Appendix A1

Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO

(submitted by the ISO on behalf of San Diego Gas and Electric Company Transmission Owner)

The diagrams of transmission lines and associated facilities placed under the control of the ISO submitted hereby the ISO on behalf of SDG&E are amended as follows.

Item 1: Imperial Valley Switchyard 230kV Breakers Nos. 4132 and 5132 shown in the diagram as non-SDGE facilities should be shown as SDG&E owned. Furthermore, these breakers are being placed under the operational control of the ISO.

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%.

Supplement To SDG&E's Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), the transmission system[3] of San Diego Gas & Electric Company (SDG&E) is placing under the California Independent System Operator's Operational Control meets the Applicable Reliability Criteria,[4] with the following exceptions: (1) SDG&E has not yet re-assessed its system performance for any reliability criteria added or modified by the new North American Electric Reliability Council (NERC) Planning Standards and Guides, released in September, 1997;[5] (2) SDG&E has also not yet re-assessed its system performance for the revised simultaneous generator outage criteria which was approved by the WSCC Board of Trustees on October 27, 1997.[6]

Pursuant to Section 4.1.5(i), SDG&E does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of SDG&E utility service pursuant to AB 1890. However, SDG&E cannot warrant that these right-of-way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from SDG&E's rights, pursuant to its physical ownership and operation of transmission facilities.

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[3] Including upgrades and operational plans for the transmission lines and associated facilities.

[4] Based upon studies with SDG&E's forecast peak 1998 system loads and the Applicable Reliability Criteria, including the WSCC Reliability Criteria for Transmission Planning and WSCC Minimum Operating Reliability Criteria dated March 1997, and the SDG&E Local Reliability Criteria as submitted to the California ISO by letter dated December 15, 1997.

[5] Assessments of SDG&E's transmission system using NERC Planning Standards and Guides, released September 16, 1997 will be performed in accordance with the ISO's coordinated transmission planning process as provided for in the ISO Tariff, Section 3.2.2 and under schedules adopted in that process.

[6] The revised criteria will be cooperatively assessed by SDG&E and the ISO as soon as possible but not later than May 1, 1998. SDG&E also may not meet the WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high.

APPENDIX A.2: CITY OF VERNON

TRANSMISSION ENTITLEMENTS

[NOT USED]

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
3. North to South on COTP South to North on COTP	Vernon, PG&E, TANC, WAPA, City of Shasta Lake, Carmichael Water District, San Juan Suburban Water District, CDWR (Operating Agent-Western (SNR)) (7)		COTP Interim Participation Agreement.		Upon execution of a superseding long-term participation agreement or upon a unanimous decision by the executing parties to terminate this Agreement.	121 MW N-S 92 MW S-N
4. Sylmar-Midway (After 12/31/2007).	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	72	(1) See Notes	93 MW
5. Sylmar-Laguna Bell - Through midnight December 31, 2002. - After midnight December 31, 2002.	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	 93 MW 60 MW
6. Midway-Laguna Bell (After 12/31/2007).	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	72	(1) See Notes	60 MW
7. Mead-Laguna Bell	Vernon, Edison	Bi-Directional	Edison-Vernon Mead FTS	207	(2) See Notes	26 MW

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
8. Victorville-Lugo Midpoint-Laguna Bell Note: Service is reduced to 11 MW on 1/1/2003, unless Vernon elects by 10/1/2002 to extend up to an additional 64 MW of service.	Vernon, Edison	Bi-Directional	Edison-Vernon Victorville-Lugo Midpoint FTS	54	(3) See Notes	75 MW
9. Adelanto-Victorville/Lugo Midpoint (4a)	Vernon, Los Angeles	Bi-Directional	Los Angeles-Vernon Adelanto-Victorville/Lugo FTS		(4b) See Notes	75/81 MW (8)
10. NOB-Sylmar-Midway Midway-Sylmar-NOB (6)	Vernon, PG&E	Bi-Directional	Transmission Service Exchange Agreement Between PG&E and the City of Vernon	148	(5) See Notes	93 MW N-S 82 MW S-N

Summary - Details are in each Agreement

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

Notes:

(1) Contract Termination: Upon termination of Vernon's ownership of a portion of the COTP entitlement.

(2) Contract Termination: Upon termination of Vernon's Hoover Power Sales contract with WAPA; or 12/31/2007 based on proper notice from Vernon to Edison.

(3) Contract Termination: Upon permanent removal from operation of the Mead-Adelanto 500 kV Transmission Project; or 12/31/2007 based on proper notice from Vernon to Edison.

(4a) DWP No. 10396.

(4b) Contract Termination: Upon permanent removal from operation of the Mead-Adelanto 500 kV Transmission Project; or four years prior written notice by either party.

(5) Contract Termination:

1. This Agreement may be terminated on July 31, 2007:

   A. By PG&E with one year notice to Vernon, if PG&E has not retained for the remaining term of this Agreement at least a 659 MW transmission entitlement in DC Line at NOB.

   B. By Vernon, if PG&E's entitlement in the DC Line after July 2007 results in an arrangement for the operation of DC Line as to reduce transmission capability.

   C. If the DC Line or COTP facilities are retired.

2. In the event City elects to participate in an alternative project that provides City with transmission capability between the Southern Terminus of COTP and Edison's system, City may terminate this Agreement by written notice to PG&E at least five (5) years in advance of such termination.

3. Otherwise, the Agreement remains in effect until September 2042.

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

<u>Notes</u>: (continued)

(6) Transfer capability at Sylmar: In accordance with Section 7.2 of the PG&E-Vernon Transmission Service Exchange Agreement and Section 6.1 of the Edison-Vernon Firm Transmission Service Agreement, Vernon receives the following transmission services:

- a) 93 MW from NOB to Sylmar.
- b) 82 MW from Sylmar to NOB.
- c) 93 MW from Sylmar to Laguna Bell (60 MW after midnight December 31, 2002).
- d) 93 MW from Laguna Bell to Sylmar (60 MW after midnight December 31, 2002).
- e) 60 MW to Sylmar through the regulating transformers.
- f) 53 MW from Sylmar through the regulating transformers.
- g) 93 MW from Sylmar to Midway, after 12/31/2007.
- h) 93 MW from Midway to Sylmar, after 12/31/2007.

(7) For information only.

(8)

(9) Effective July 1, 2002, Vernon’s Entitlement on the Adelanto-Victorville/Lugo line increases from 75 MW to 81 MW.

APPENDIX A: CITY OF ANAHEIM TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1	IPP-Adelanto Switching Station	Anaheim-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	339 MW (N-S) 247 MW (S-N)
2	Marketplace Substation-Adelanto	Anaheim-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
	Marketplace Substation-McCullough	“	“	“		“	118 MW
3	Westwing-Mead 500 kV	Anaheim-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	47 MW
	Marketplace-Mead 500 kV	“	“	“		“	110 MW
	Mead 500 kV-Mead 230 kV	“	“	“		“	110 MW
	Marketplace Substation-McCullough	“	“	“		“	110 MW
4	Adelanto-Victorville/Lugo	Anaheim-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	110 MW
5	Adelanto-Victorville/Lugo	Anaheim-LADWP	North-South	IPP Base Capacity Transmission Service Agreement		See Note 2	212 MW
6	Adelanto-Victorville/Lugo	Anaheim-LADWP	North-South	IPP Additional Capacity Transmission Service Agreement		See Note 3	127 MW
7	IPP-Mona Substation	Anaheim-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	381 MW
	IPP-Gonder Substation	“	“	“		“	54 MW
8	Nevada-Oregon Border-Sylmar	Anaheim-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	24 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 Anaheim interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Anaheim 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.

APPENDIX A: CITY OF AZUSA

TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Vernon	Bi-Directional	- MAP Joint Ownership Agreement. - Adelanto Switching Station Interconnection Agreement. - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Coordinating Committee.	19 MW

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
2. Mead-Phoenix Project (MPP)	SCPPA, MSR, Vernon, SRP, APS		- MPP Joint Ownership Agreement - Westwing Substation Interconnection Agreement - Mead Interconnection Agreement - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Management Committee.	
a) Westwing-Mead b) Mead Substation c) Mead-Marketplace		Bi-Directional Bi-Directional Bi-Directional				3 MW 0 MW 3 MW
3. Mead - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Hoover FTS	247.4	(1) See Notes	4 MW
4. Victorville-Lugo - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Palo Verde Nuclear Generating Station FTS	247.6	(2) See Notes	4 MW
5. Victorville-Lugo - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Pasadena FTS	247.8	(3) See Notes	14 MW

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
6. Sylmar - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa San Juan Unit 3 FTS	247.29	(4) See Notes	 10 MW: CY 2004 through termination
7. Mead - Rio Hondo	Azusa, Edison	Bi-Directional	Edison-Azusa Sylmar FTS	247.24	(5) See Notes	8 MW
8. Sylmar - NOB	Azusa, Pasadena, Burbank	Bi-Directional	Pacific Intertie Direct Current FTS		(6) See Notes	3MW
9. ANPP (Devers) - Sylmar	Azusa, Los Angeles	Bi-Directional	Los Angeles - Azusa ANPP/Sylmar FTS	DWP No. 10021	(7) See Notes	10 MW
10. Victorville-Lugo - Adelanto	Azusa, Los Angeles	Bi-Directional	Los Angeles - Azusa Adelanto-Victorville/Lugo FTS	DWP No. 10345	(8) See Notes	19 MW

Summary- details are in each agreement.

NOTES:

(1) Contract Termination: Upon written agreement between the Parties to terminate the FTS Agreement or termination of Electric Service Contract, provided that the termination of FTS Agreement shall not occur prior to January 1, 2003.

(2) Contract Termination: Upon written agreement between the Parties to terminate the FTS Agreement, termination of Azusa's entitlement to PVNGS, or termination of the Arizona Nuclear Power Project Participation, provided that the termination of the FTS Agreement shall not occur prior to January 1, 2003.

(3) Contract Termination:	Upon written agreement between the Parties to terminate the FTS Agreement or termination of City's ownership in San Juan Unit 3, provided that termination of this Transmission Service Agreement shall not occur prior to January 1, 2003.
(4) Contract Termination:	Same as (3)
(5) Contract Termination:	Same as (3)
(6) Contract Termination:	This agreement will be terminated effective September 30, 2009.
(7) Contract Termination:	This agreement shall be terminated upon the earlier of: (i) 2400 hours on December 31, 2023; (ii) by mutual agreement of the Parties; (iii) thirty-six months after Los Angeles has provided written notice that the Agreement is to terminate, provided, however, such notice of termination shall not be given prior to December 31, 2000; or (iv) Azusa may elect to discontinue service under this Agreement by written notice to Los Angeles within sixty days of the mailing date of any subsequent rate for transmission service established under Section 10.3 of the Agreement. If Azusa so elects, this Agreement shall terminate on the last day of the second full month following the mailing date of Azusa's notice.
(8) Contract Termination:	This agreement shall be terminated upon the earlier of: (i) four years prior written notice by either Party, which notice shall not be given before one year after the Date of Firm Operation; (ii)the date of retirement of the Mead-Adelanto Project; (iii) the date the point of interconnection on the Victorville-Lugo transmission line is permanently removed from service; (iv) the in-service date of the Adelanto-Lugo transmission line, as such date is defined pursuant to the agreements relating thereto; (v) a date determined pursuant to Section 4.3 of the Agreement; or (vi) a date mutually agreed upon by the Parties.

APPENDIX A: CITY OF BANNING
TRANSMISSION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	Marketplace Substation-Adelanto	Banning-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		Oct 31, 2030	12 MW
2.	Westwing-Mead-Marketplace 500 kV	Banning-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		Oct 31, 2030	3 MW
3.	Marketplace-McCullough 500 kV	Banning-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		Oct 31, 2030	12 MW 3 MW
4.	ANPP-Sylmar	Banning-LADWP	Bi-directional	ANPP/Sylmar 15 MW Transmission Service Agreement		See Note 1	15 MW
5.	Adelanto-Victorville/Lugo	Banning-LADWP	To Victorville	Adelanto-Victorville/Lugo Firm Transmission Service Agreement		See Note 2	12 MW
6.	Nevada-Oregon Border-Sylmar	Banning-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		Sep 30, 2009	1 MW
7.	Victorville/Lugo-Devers 115 kV	Banning-SCE	To Devers	Palo Verde Nuclear Generating Station Firm Transmission Service Agreement		See Note 3	3 MW
8.	Victorville/Lugo-Devers 115 kV	Banning-SCE	To Devers	Sylmar Firm Transmission Service Agreement		See Note 4	5 MW
9.	Mead 230 kV-Devers 115 kV	Banning-SCE	To Devers	Hoover Firm Transmission Service Agreement		See Note 5	2 MW
10.	Devers 500 kV-Devers 115 kV	Banning-SCE	To Devers	1995 San Juan Unit 3 Firm Transmission Service Agreement		See Note 6	15 MW

Notes

1. Agreement terminates on: (i) December 31, 2023; or (ii) 36-months notice by LADWP.
2. Agreement terminates on: (i) 4-years written notice by either party; or (ii) the date of retirement of the Mead-Adelanto Project; (iii) the date the point of interconnection on the Victorville/Lugo line is permanently removed from service; (iv) the in-service date of the Adelanto-Lugo transmission line, as such date is defined pursuant to the agreements relating thereto.
3. Agreement terminates on: (I) twelve months notice by Banning; (ii) termination of Banning's interest in Palo Verde Nuclear Generating Station Unit 2; or (iii) unacceptable FERC modification.
4. Agreement terminates on: (I) twelve months notice by Banning; (ii) termination of Banning's interest San Juan Unit 3; or (iii) unacceptable FERC modification.
5. Agreement terminates on: (I) twelve months notice by Banning; (ii) termination of the Electric Service Contract between Western and Banning; or (iii) unacceptable FERC modification.
6. Agreement terminates on: (I) twelve months notice by Banning; (ii) termination of Banning's interest San Juan Unit 3; or (iii) unacceptable FERC modification.

APPENDIX A: CITY OF RIVERSIDE
TRANSMISSION 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: CITY OF PASADENA TRANSMISSION ENTITLEMENTS

Ref	Point of Receipt-Delivery (see note 2)	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
B1.	IPP - Adelanto Switching Station	Pasadena-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	113 MW
B2.	Mead - Marketplace - Adelanto	Pasadena-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	75 MW
B3.a	Westwing – Mead 500 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	33 MW
B3.b	Mead 500 kV - Marketplace 500 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	60 MW
B3.c	Mead 500 kV - Mead 230 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	25 MW
B4.	Marketplace 500 - McCullough 500 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix and Mead-Adelanto Project Transmission Service Contracts		31-Oct-30	135 MW
B5.	Adelanto - Victorville	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW
B6.a	IPP - Mona Substation	Pasadena-LADWP - Utah Participants	Bi-directional	IPP Excess Power Sales Sales Agreement		15-Jun-27	104 MW [Note 3]
B6.b	IPP - Gonder Substation	Pasadena-LADWP - Utah Participants	Bi-directional	IPP Excess Power Sales Sales Agreement		15-Jun-27	16 MW [Note 3]
B7.	Sylmar – T.M. Goodrich	Pasadena-SCE	Bi-directional	230-KV Interconnection and Transmission Agreement		04-Aug-10	200 MW
B8.a	Adelanto - Sylmar	Pasadena-LADWP	Bi-directional	IPP Transmission Service Agreement 14443		15-Jun-27	110 MW [Note 2]
B8.b	Adelanto - Sylmar	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW [Note 2]
B9.	Victorville – Sylmar	Pasadena-LADWP	Bi-directional	Victorville-Sylmar Transmission Service Agreement 14444		Note 1	26 MW [Note 1, Note 2]
B10.	Mead –McCullough	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW
B11.	McCullough - Victorville	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW
C1.	Nevada Oregon Border - Sylmar	Pasadena-LADWP	Bi-directional	Pacific Intertie D-C Transmission Facilities Agreement		14-Apr-41	72 MW [Note 2]
C2.	McCullough – Victorville	Pasadena-LADWP	Bi-directional	McCullough Victorville Line 2 Transmission Agreement 10463		31-May-30	26 MW

Notes

1 This contract is coterminous with the McCullough Victorville Line 2 Transmission Agreement.

2 Deliveries to Sylmar point of delivery are at the SCE/CAISO side of the 230kV bus.

3 The contract amount is subject to change by the terms of the contract.

* * *

APPENDIX A: STARTRANS IO, L.L.C.

TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Startrans IO (Operating Agent-LA)	Bi-Directional	- MAP Joint Ownership Agreement - Adelanto Switching Station Interconnection Agreement - Marketplace-McCullough 500 kV Interconnection Agreement		As agreed to by the owners and approved by the Project Coordinating Committee.	81 MW
2. Mead-Phoenix Project (MPP)	SCPPA, MSR, Startrans IO, SRP, APR (Operating Managers – SRP, Western (DSW))		- MPP Joint Ownership Agreement - Westwing Substation Interconnection Agreement. - Mead Interconnection Agreement - Marketplace-McCullough 500 kV Interconnection Agreement		As agreed to by the owners and approved by the Project Management Committee.	
a) Westwing-Mead b) Mead Substation c) Mead-Marketplace		Bi-Directional Bi-Directional Bi-Directional				28 MW 47 MW 75 MW

TRANSMISSION CONTROL AGREEMENT

APPENDIX B

Encumbrances

PG&E APPENDIX B

List of Encumbrances on Lines and Facilities, and Entitlements Being Placed Under ISO Operational Control (per TCA Appendix A1 & A2)[7]

(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.	

[7] 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.

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.

EXHIBIT B-1
(TO PG&E APPENDIX B)

Path 15 Curtailment Instructions
For Existing Encumbrances Across the Path 15 Interface

Purpose and Objective

Path 15 Curtailment Instructions provide direction to the ISO regarding the management of congestion on Path 15 and are submitted to the ISO, as part of the Transmission Rights and Transmission Curtailment (TRTC) Instructions, by PG&E as the Responsible PTO for the Existing Transmission Contract (ETC) rights on the path.

These instructions are to be administered and adhered to by the ISO except when the ISO determines that system reliability requires that other steps be taken. The ISO is solely responsible for continued system reliability and must unilaterally take all steps necessary to preserve the system in times of emergency.

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 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
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.

SDG&E APPENDIX B

SDG&E'S ENCUMBRANCES

I. Local Furnishing Transmission System Encumbrances

The ISO shall exercise Operational Control over SDG&E's Local Furnishing Transmission System consistent with the following Encumbrances in accordance with the Local Furnishing Debt Operating Procedures that SDG&E has provided the ISO:

A. Section 9600(a)(6) of the California Public Utilities Code provides that Participating TOs shall not be compelled to violate restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding use of transmission facilities existing as of December 20, 1995.

   SDG&E's transmission facilities and other electric properties are financed in part with the proceeds of Local Furnishing Bonds. Prior to December 20, 1995, pursuant to provisions of the loan agreement, engineering certificates, and tax certificates and agreements associated with outstanding Local Furnishing Bonds issued for its benefit, SDG&E has convenanted not to take or permit any action that would jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit. Accordingly, notwithstanding anything to the contrary contained in the Agreement, including SDG&E's agreement to be bound by the terms of the Restated and Amended ISO Tariff and the Restated and Amended TO Tariff, SDG&E may not take (nor may SDG&E allow the ISO to take) any action that would jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit, including (without limitation) the actions specified below.

B. Absent an approving written opinion of nationally recognized bond counsel selected by SDG&E, SDG&E will not operate its facilities (or allow its facilities to be operated) so as to cause or permit a cumulative annual net outbound flow of electric energy from the points of interconnection between (i) SDG&E's wholly-owned transmission lines which are directly connected to SDG&E's electric distribution facilities in San Diego and Orange Counties, and (ii) other electric properties. As of January 1, 1998, these interconnection points include:

   1. the point at the International Border where SDG&E's ownership interest in the 230 kV Miguel/Tijuana transmission

line interconnects with Comision Federal de Electridad's ownership interest in the Miguel/Tijuana transmission line;

2. the set of points at the San Onofre Nuclear Generating Station ("SONGS") where SDG&E's wholly-owned transmission facilities interconnect with a switchyard but which is owned (in whole or in part) by Southern California Edison Company ("SCE");

3. the point where SDG&E's wholly-owned segment of the 500 kV Miguel/Imperial Valley transmission line interconnects with the Imperial Valley Substation;

4. the point at the San Diego/Imperial Valley border where SDG&E's ownership interest in a 2.5 mile-long radial distribution line interconnects with Imperial Irrigation District's ownership interest in that same distribution line;

5. the point at the Riverside/Orange County border and the Riverside/San Diego County border where SDG&E's ownership interest in several isolated distribution lines interconnect with SCE's ownership interest in those same distribution lines;

6. the point where SDG&E's wholly-owned Narrows Substation intereconnects with transmission facilities which are owned by Imperial Irrigation District.

C. For purposes of paragraph B, net flows shall be calculated by treating as an outbound flow at the SONGS switchyard bus all electric energy generated at SONGS on behalf of SDG&E (i.e., consequent to SDG&E's interest in SONGS) that is not transmitted into SDG&E's electric service area in San Diego and Orange Counties. Electric energy generated at SONGS on behalf of SDG&E that is transmitted into SDG&E's service area, whether for delivery to retail customers of SDG&E or for other uses, shall not be treated as an inbound flow at the SONGS switchyard bus interconnection for purposes of this calculation.

D. SDG&E will not operate its facilities (or allow its facilities to be operated) so as to curtail delivery of electric energy to its native load customers involuntarily in order to provide electric energy to customers outside of its electric service territory in San Diego and Orange Counties, unless such curtailment is necessitated by the failure of facilities either partially or wholly owned by SDG&E.

E. Upon SDG&E's receipt of a written request by the ISO to take (or to refrain from taking) any action that SDG&E believes might jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit, SDG&E in good faith shall promptly seek to obtain an opinion (of the type generally regarded in the municipal bond market as unqualified) from a nationally recognized bond counsel selected by SDG&E that the requested action (or inaction) will not adversely affect such tax-exempt status. Until the opinion of bond counsel described above is obtained, SDG&E shall not be required to take (or to refrain from taking) the specified action, and the ISO shall exercise its Operation Control consistent with such limitation.

F. If the ISO proposes to set rates for transmission over SDG&E's transmission facilities based in whole or in part upon the costs to Participating Transmission Owners other than SDG&E (see, e.g., California Public Utilities Code § 9600(a)(2)), the ISO will return Operating Control over SDG&E's transmission facilities to SDG&E unless SDG&E, in good faith, has obtained an opinion (of the type generally regarded in the municipal bond market as unqualified) from nationally recognized bond counsel selected by SDG&E that the proposed ratemaking will not adversely affect the tax-exempt status of interest on Local Furnishing Bonds issued for the benefit of SDG&E.

G. If SDG&E has been unable to obtain the unqualified opinion of bond counsel described in sections E and F above, upon written request by a entity eligible to file an application under Section 211 of the Federal Power Act ("FPA")(or the ISO acting as its agent)(collectively, the "Eligible Entity"), SDG&E in good faith shall promptly seek to obtain a ruling from the Internal Revenue Service that the requested action (or inaction) or transmission rates will not adversely affect the tax-exempt status of interest on Local Furnishing Bonds issued for the benefit of SDG&E. If such a ruling cannot be obtained, SDG&E will not object to an Eligible Entity seeking an order under Section 211 of the FPA with respect to the requested action (or inaction) or transmission rates.

II. Mortgage Lien

The ISO shall acknowledge the mortgage lien set forth below:

A. The lien of the Mortgage and Deed of Trust dated July 1, 1940 between San Diego Gas & Electric Company and The Bank of California, as trustee, as amended and supplemented and in effect on the date hereof (the "SDG&E Mortgage"). The transfer of Operational Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the property subject to the SDG&E Mortgage which would be prior to the lien of the SDG&E Mortgage; however, no consent of the trustee under the SDG&E Mortgage is required to consummate the transfer of Operational Control to the ISO pursuant to this Agreement.

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.

APPENDIX B: CITY OF VERNON'S ENCUMBRANCES

	POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC NO.	CONTRACT TERMINATION	CONTRACT AMOUNT
1.	COTP [1]	Vernon, PG&E		Transmission Service Exchange Agreement Between Pacific Gas & Electric Company and the City of Vernon	148	See Notes (1) – (3)	121 MW N-S 92 MW S-N
2.		PG&E, SCE, SDG&E, and COTP Participants		Coordinated Operation Agreement	146	Earlier of: 1/1/2043, agreement governing the interconnection of the COTP with PG&E is no longer in force, or any of the binding agreements terminate.	

Contract Termination:

(1) This Agreement may be terminated on July 31, 2007:

A. By PG&E with one year notice to Vernon if PG&E has not retained for the remaining term of this Agreement at least a 659 MW transmission entitlement in DC Line at NOB.
B. By Vernon if PG&E's entitlement in the DC Line after July 2007 results in an arrangement for the operation of DC Line as to reduce transmission capability.
C. If the DC Line or COTP facilities are retired.

(2) In the event City elects to participate in an alternative project that provides City with transmission capability between the Southern Terminus of COTP and Edison's system, City may terminate this Agreement by written notice to PG&E at least five (5) years in advance of such termination.

(3) Otherwise, the Agreement remains in effect for fifty years from the effective date.

[1] PG&E is an existing PTO and a joint-owner of COTP. We believe documents relating to the COTP are submitted to the CAISO by PG&E.

Vernon has only minority ownership interests in the high voltage transmission facilities presently placed under the ISO's Operational Control by Vernon, which consist of Vernon's minority interests in COTP, MPP, MAP, and the Marketplace Substation/Expansion of and/or interconnection to these facilities require approval of the owners and/or the management committees of those facilities. Therefore, as the Commission determined in approving Vernon's TO Tariff in Docket No. EL00-105, 96 FERC ¶ 61,312 (September 14, 2001), Vernon does not have the legal authority to compel expansion of and/or interconnection to those facilities. Such encumbrances pertaining to Vernon's minority interests in the facilities turned over to ISO operational control that do not fit into the format of the table above are listed below:

Mead-Phoenix Project

1. Mead-Phoenix Project Joint Ownership Agreement and Definitions
2. Mead-Phoenix Project Fiscal Agency Agreement
3. Mead-Phoenix Project Construction Management Agreement
4. Mead-Phoenix Project Land Rights Agreement
5. Mead-Phoenix Project Operation Agreement
6. Mead-Phoenix Project, Mead-Westwing Transmission Line, Westwing Substation Interconnection Agreement (DWP No. 10408)
7. Mead-Phoenix Project, Mead Interconnection Agreement

Mead-Adelanto Project

8. Marketplace Substation Participation Agreement (DWP No. 10330)
9. Mead-Phoenix/Mead-Adelanto Projects, Marketplace-McCullough 500 kV Interconnection Agreement (DWP No. 10409)
10. Mead-Adelanto Project Joint Ownership Agreement and Definitions
11. Mead-Adelanto Project Fiscal Agency Agreement
12. Mead-Adelanto Project Construction Management Agreement (DWP No. 10335)
13. Mead-Adelanto Project Operation Agreement (DWP No. 10336)
14. Mead-Adelanto Project, Marketplace-Adelanto Transmission Line, Adelanto Switching Station Interconnection Agreement (DWP No. 10338)
15. Marketplace Static Var Compensator, Adelanto Switching Station Interconnection Agreement (DWP No. 10332)

California-Oregon Transmission Project

1. Interim Participation Agreement
2. Project Operation and Maintenance Agreement

3. COTP-Western Interconnection Agreement
4. Pacific Northwest Interim Interconnection Agreement
5. Memorandum of Understanding

APPENDIX B: CITY OF ANAHEIM
ENCUMBRANCES

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1	Mona Substation-Gonder Substation	Anaheim-Deseret G&T	Bi-directional	Mona-Gonder Transmission Service Agreement		7-Jun-94	31-Dec-09	20 MW

APPENDIX B: CITY OF AZUSA
ENCUMBRANCES

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. ANPP (Devers) - Sylmar	Azusa, Los Angeles		Los Angeles - Azusa ANPP/Sylmar FTS	DWP No. 10021		10 MW

<u>Los Angeles – Azusa ANNP/Sylmar FTS</u>:
Pursuant to Section 6.2 of the Los Angeles – Azusa ANNP/Sylmar FTS, the Los Angeles Department of Water and Power is entitled to schedule energy on a nonfirm basis over the 10 MW of bidirectional transmission service between Palo Verde and Sylmar to the extent Azusa does not use the transmission service.

Summary- details are in each agreement.

APPENDIX B: CITY OF RIVERSIDE
ENCUMBRANCES

Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1. Mona Substation-Gonder Substation	Riverside-Deseret G&T	Bi-directional	Mona-Gonder Transmission Service Agreement		17-Jun-94	31-Dec-09	20 MW

APPENDIX B: CITY OF PASADENA
ENCUMBRANCES

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1.	Nevada/Oregon Border – Sylmar	Pasadena - Riverside, Azusa, Banning, Colton	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		01-Oct-89	30-Sep-09	14 MW
2.	Nevada/Oregon Border - Sylmar	Pasadena - Anaheim	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		01-Oct-89	30-Sep-09	10 MW

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

<u>ISO TRANSMISSION MAINTENANCE STANDARDS</u>

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.

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.

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

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.

<u>Forced Outage$^{(IMS)}$ Frequency:</u>

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.

<u>NOTES:</u>

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:

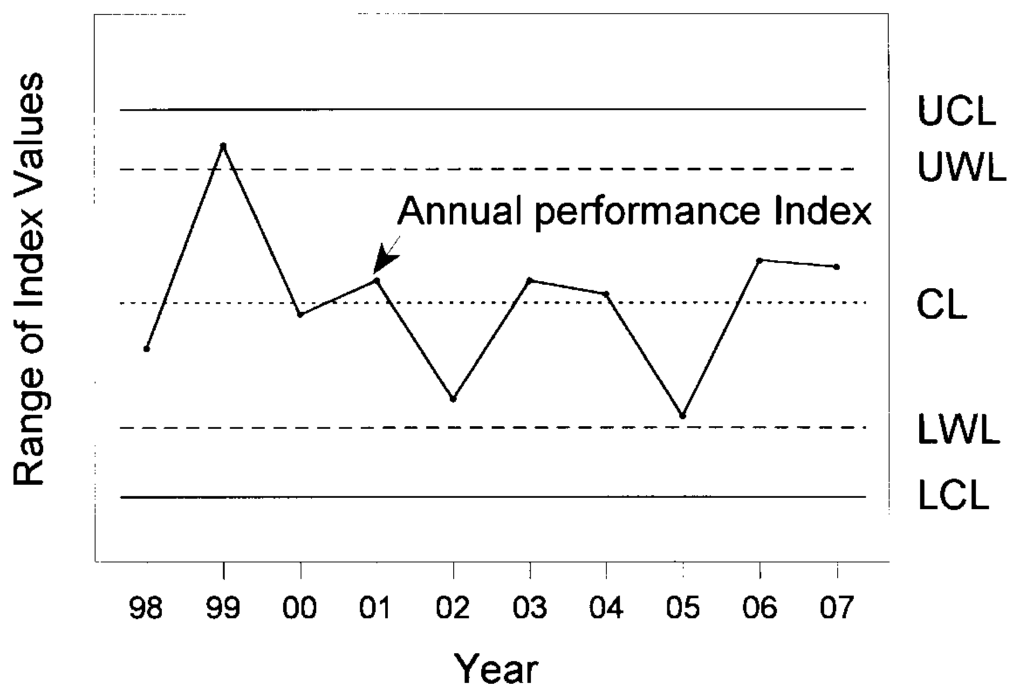

Figure 4.2.1 Sample Control Chart

- <u>Index 1</u>: Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits.
- <u>Index 2</u>: 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.

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

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

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 “ith“ 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 "i^{th}" 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.

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 4.1.1 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 "k^{th}" 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 "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 "k^{th}" 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		Performance Status Indicated by Test Results	
	Number	Results	Improvement	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.

* * *

DIABLO CANYON NUCLEAR POWER PLANT
UNITS 1 & 2

REQUIREMENTS FOR OFFSITE
POWER SUPPLY OPERABILITY
REVISION 1

DCPP 1&2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

OVERVIEW

The DCPP Operating License and Technical Specifications require two physically independent sources (not necessarily on separate right of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both sources is acceptable. Each of these sources shall be designed to be available in sufficient time following a loss of all DCPP onsite alternating current power supplies and the other offsite electric power circuit. One of these sources shall be designed to be available within a few seconds following a loss-of-coolant accident. For DCPP, the sources available within seconds are the 230 kV grid interface and the second source is the 525 kV grid interface.

During normal operation, each DCPP unit's electrical loads are supplied from the unit's main onsite electrical generator. If the generator is not available, either due to unit shutdown or other reason, the loads (safety related and non-safety related) are transferred to the 230 kV grid. In addition DCPP has a delayed transfer capability to the 525 kV grid. The offsite power source is sometimes referred to as the preferred power supply in the regulatory documents.

The basic requirement for the offsite power supply is that it provides sufficient capacity and capability for safe shutdown and design basis accident mitigation. When this condition is met, the offsite power supply is considered Operable with respect to the DCPP Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If either source of the offsite power system is declared Inoperable, action must be taken to shut down an on-line DCPP units(s) and, for an off-line unit, to suspend activities as required by the DCPP Operating License and Technical Specifications. DCPP must also perform additional diesel testing. The offsite power system is considered Inoperable if either source is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition, which renders the offsite power unavailable for safe shutdown and emergency purposes.

In specific terms, the offsite power supply voltages (at the DCPP switchyards) must stay within the range of 207 kV to 240 kV and 525 kV to 545 kV under post accident operating conditions. During normal operation, the 230 kV voltage must maintain above 207 kV such that when DCPP transfers its load from the onsite source to the offsite source the voltage does not decrease below 207 kV. During normal operation, the 230 kV voltage at DCPP 230 kV switchyard should meet the 230 kV voltage requirements identified in PG&E Operating Instruction O-23. Otherwise, that offsite power source may be considered Inoperable. Since a design basis accident can result in a unit trip, it is imperative that the trip does not impair the operability of the offsite power system. Therefore, following a trip of a

DCPP unit (i.e., the unit breakers open) and assuming the other DCPP unit was already shutdown, the DCPP switchyard voltage must recover to and be maintained at or above 207 kV within 16 seconds following the unit trip. If this condition cannot be met, then the offsite power source is considered Inoperable, and action must be taken to shut down the operating DCPP unit(s). In addition, the 500 kV and 230 kV grid must remain stable if both DCPP units trip.

System Operating procedures 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 immediately communicated to the DCPP operating staff for Operability determination.

SPECIFIC REQUIREMENTS

Note: This section identifies the operational requirements for the DCPP offsite power supply. These requirements are part of the DCPP design basis and licensing basis and include PG&E System Operating Instruction 0-23 as revised as necessary. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating DCPP unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to the ISO, PG&E and the DCPP operating staff for operability determination. Changes in the operation of the transmission network that conflict with these requirements requires prior approval by PG&E.

1. Three transmission lines into the 500 kV DCPP switchyard and two lines into the 230 kV DCPP switchyard are normally in service. Any change that alters the performance capabilities of either offsite source at the applicable switchyard requires prior approval by PG&E (DCPP) and the ISO.

   No line may be removed from service at anytime without prior notification to the DCPP Operations Department. At least two independent sources of power, the 500 kV and the 230 kV systems, between the transmission network (grid) and DCPP switchyards shall be available at all times. PG&E System Operating Procedure, 0-23, Operating Instructions for Reliable Transmission Service for Diablo Canyon, provides specific requirements to determine operability of these sources.

2. With both Diablo Canyon units off-line, the DCPP 500 kV and 230 kV offsite power source should be capable of providing 130 MVA (i.e. dual unit orderly shutdown) to Diablo Canyon for normal operation, safe shutdown, and design basis accident mitigation.

3. The minimum grid voltage at DCPP 230 kV switchyard shall be maintained at or above 230 kV for normal operation with all Los Padres 230 kV elements

(See list below) in service. In the event of a system disturbance or line outage that can cause the DCPP voltage to dip below 230 kV, including the trip of a DCPP unit, the grid voltage shall recover to 207 kV or above within 16 seconds.

<u>Los Padres Area Major 230 kV Elements</u>	<u>Major 500 kV Elements</u>
DCPP – Mesa Line	DCPP-Gates Line
Morro Bay – Mesa Line	DCPP-Midway Line #1 & #2 Line
Morro May – DCPP Line	
Morro Bay – Templeton Line	
Morro Bay - Midway Line #1 or #2 Line	
Morro Bay - Gates Line #2 Line	
Largest Los Padres area generator other than DCPP	
DCPP 230 kV capacitor banks	
Mesa 115 kV capacitor banks	

4. Planning and operating reliability criteria shall result in plans for the following events without loss of grid stability or availability:

    a) The loss of two DCPP units.

    b) The loss of any generating unit on the PG&E grid.

    c) The loss of any major transmission circuit or intertie on the PG&E grid.

    d) The loss of any large load or block of load on the PG&E grid.

5. The maximum grid voltage at the DCPP 230 kV and 500 kV switchyards shall be maintained at or below 240 kV and 545 kV, respectively, unless required to preserve transmission network integrity.

6. The 500 kV system shall be maintained between 525 kV and 545 kV. Operation of DCPP is limited between 24.375 kV and 26.25 kV (i.e. 0.975 p.u. and 1.05 p.u.).

PG&E, in coordination with the ISO, shall perform and update system studies based on changing grid conditions (load growth, etc.) to identify critical conditions that could render the DCPP 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 effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition that renders the offsite power supply unavailable for safe shutdown and emergency purposes. Procedures and programs shall be in effect to ensure that the DCPP operating staff is immediately notified of such conditions. Grid conditions that are more severe with respect to DCPP switchyard voltages or otherwise unanalyzed render the offsite power supply Inoperable. DCPP operating staff shall be immediately notified of such conditions. Auditable records of system study results shall be maintained. Study results, including revisions and updates, shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPP) and the ISO. 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 transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPP) and the ISO.

System studies shall consider the interconnections between PG&E, and other utilities in the Western Electricity Coordinating Council (WECC) region.

7. In the event of a complete loss of the DCPP offsite power supply (i.e. both the 230 kV and 500 kV grid interfaces) both the ISO and PG&E shall establish the following restoration priorities:

    a) Highest possible priority shall be given to restoring power to the DCPP switchyards.

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

    c) Repair crews engaging in power restoration activities for DCPP 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.

8. Grid frequency shall be maintained at 60 Hertz (nominal). The following operations are initiated for low system frequency conditions:

    a) At 59.65 Hz, E19 & E20 interruptible customers are tripped.

    b) PG&E complies with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

9. Patrol and inspection of PG&E transmission lines shall be performed in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice.

10. Line insulators between the plant and switchyard shall be washed by PG&E on an appropriate wash cycle during the wash season in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line

Maintenance Practice to reduce line outages that may result from flashovers due to possible accumulated contamination.

11. Maintenance, testing and calibration of DCPP switchyard equipment and protective relays shall be performed in accordance with the current CAISO approved PG&E Electrical Station Maintenance Practice.

12. PG&E (DCPP) maintains a safety analysis for DCPP (Section 8.0, Electric Power of DCPP 1&2 Final Safety Analysis Update Report (FSAR)). PG&E (DCPP) is required by 10CFR50.71(e) to submit to the NRC periodic updates to the FSAR. The requirements contained in this Appendix E are documented in the FSAR. Any changes to these requirements, or the Bulk Power Transmission System Reliability criteria used as a basis for compliance with a requirement, shall be transmitted by both the ISO and PG&E (Transmission operator) to PG&E (DCPP) for prior approval.

These Specific Requirements mirror existing operating protocols, equipment, regional and national reliability organization standards and are subject to modification as necessary when new standards, equipment or protocols are adopted or updated.

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.

This 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 off site 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:

<u>Note:</u> 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).

VI 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

TRANSMISSION CONTROL AGREEMENT

APPENDIX F

NOTICES

NOTICES

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