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April 7, 2004

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

Re: City of Anaheim and Riverside, California
Docket Nos. EL03-15-000 and EL03-20-000

Dear Secretary Salas:

Enclosed for filing please find an original and seven copies of the prepared cross-answering testimony and exhibits of Deborah A. Le Vine and Ziad Alaywan on behalf the California Independent System Operator Corporation ("ISO") filed in the above-referenced dockets. Two copies are being provided to the Presiding Judge.

An additional copy of the enclosed prepared cross-answering testimony and exhibits is provided to be time-stamped and returned to our messenger. Thank you for you assistance in this matter.

Respectfully submitted,

Michael E. Ward
Swidler Berlin Shereff Friedman, LLP
Counsel for the California
Independent System Operator
Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Anaheim, California	)	Docket Nos. EL03-15-000
	)	
City of Riverside, California	)	EL03-20-000

PREPARED CROSS-ANSWERING TESTIMONY OF DEBORAH A. LE VINE ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Anaheim, California	)	Docket Nos. EL03-15-000
	)	
City of Riverside, California	)	EL03-20-000

SUMMARY OF
PREPARED CROSS-ANSWERINGTESTIMONY OF
DEBORAH A. LE VINE
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Ms. Le Vine responds to the testimony of David Marcus on behalf of the California Department of Water Resources State Water Project. Ms. Le Vine explains that there are a number of transmission lines other than the NTS and STS that are outside the ISO Control Area but under the ISO's Operational Control. Ms Le Vine states that the ISO does not have any greater operational control over those transmission lines than over the NTS and STS.

Ms. Le Vine also explains that the FTRs that Anaheim and Riverside receive in connection with the NTS and STS do not differ from other FTRs. The scheduling priority they provide only applies in the Day-Ahead Market, and Anaheim and Riverside will only receive these FTRs during the Transition Period of the ISO's transmission Access Charge. The Commission has approved the grant of FTRs to New Participating Transmission Owners.

Finally, Ms. Le Vine testifies that the inclusion of the NTS and STS increases the transmission Access Charge by $0.25/MWh in the East Central TAC Area and by $0.06/MWh in the North and South TAC Areas.

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Deborah A. Le Vine and I am the Director of Contracts for the California Independent System Operator (ISO). My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed testimony to explain the role of Anaheim's and Riverside's Entitlements in the Northern Transmission System ("NTS") and the Southern Transmission System ("STS") as part of the ISO Controlled Grid.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to respond to testimony filed by Dr. David Marcus on behalf of the California Department of Water Resources State Water Project. In the process of responding to Dr. Marcus, I will also be responding to arguments advanced by Southern California Edison.

Q WHAT TOPICS WILL YOU DISCUSS?

A. Dr. Marcus makes five basic arguments:

(1) Dr. Marcus asserts that the STS and NTS are generation outlet facilities, which should not be included in a Transmission Revenue Requirement. I have already addressed this issue in my Direct Testimony, and this testimony has also been effectively rebutted by Commission Staff.

(2) Dr. Marcus asserts that the ISO does not have meaningful Operational Control over the NTS and STS. Although I addressed this matter in my Direct Testimony, I will elaborate further in this testimony.

(3) Dr. Marcus asserts that the ISO is providing discriminatory access to the STS and NTS to Anaheim and Riverside. Mr. Ziad Alaywan of the ISO will provide testimony on this subject.

(4) Dr. Marcus contends Anaheim's and Riverside's TRRs are not consistent with the Entitlements in the NTS and STS or include costs for facilities that are not used and useful. I will discuss Firm Transmission Rights ("Firm Transmission Rights") and the costs imposed on transmission customers in this regard. Mr. Alaywan will discuss other matters.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. I will be using terms defined in the Master Definitions Supplement, Appendix A of the ISO Tariff.

OPERATIONAL CONTROL

Q. IN YOUR DIRECT TESTIMONY, YOU STATED THAT FOR ISO CONTROLLED GRID FACILITIES OUTSIDE THE ISO CONTROL AREA, SUCH AS THE STS AND NTS, THE ISO'S OPERATIONAL CONTROL IS LARGELY LIMITED TO ISO COORDINATING SCHEDULES, OUTAGES AND MONITORING WITH THE APPLICABLE CONTROL AREA OPERATOR. ARE THERE OTHER TRANSMISSION LINES OUTSIDE THE ISO'S CONTROL AREA THAT ARE UNDER THE ISO'S OPERATIONAL CONTROL?

A. Yes, the Eldorado-Moenkopi-Four Corners line, the Pacific DC Intertie, Mead-Phoenix Project, the Mead-Adelanto Project, Marketplace-McCullough, Mead 500/230 kV, Marketplace-Mead, and Entitlements from Adelanto to the Victorville-Lugo Midpoint.

Q DR. MARCUS TESTIFIES THAT THE ISO HAS GREATER CONTROL OVER THOSE TRANSMISSION LINES THAN OVER THE NTS AND STS. IS HE CORRECT?

A. No.

Q. ONE OF DR. MARCUS'S ASSERTIONS IS THAT THE ISO'S USE OF THE NTS AND STS IS DEPENDENT UPON THE OPERATION OF A NON-PARTICIPATING GENERATOR. DOES THAT DISTINGUISH IT FROM THE OTHER LINES OUTSIDE THE ISO'S CONTROL AREA?

A. No. The ability to use almost any transmission line is affected by generating units interconnected to the transmission line. Mr. Alaywan provides some specific examples. In the case of transmission lines outside the ISO Control Area, most generating units are not subject to Participating Generator Agreements. External generating units constitute "System Resources," which the ISO Tariff defines as "a group of resources located outside of the ISO Control Area capable of providing Energy and/or Ancillary Services to the ISO Controlled Grid." The ISO cannot control the Dispatch of System Resources; Schedules from System Resources at the ties are deemed delivered consistent with the Western Electricity Coordinating Council.

The Intermountain Generating Station is a System Resource. The same is true of generating units interconnected with other lines under the ISO's Operational Control but outside the ISO Control Area, including Southern California Edison Company's ("SCE") entitlement to the Four Corners Generating Station.

Q. HOW THEN DO YOU RESPOND TO DR. MARCUS'S ASSERTION THAT THE ISO CAN EXERT CONSIDERABLY MORE OPERATIONAL CONTROL IN THE CASE OF THE FOUR CORNERS-MOENKOPI-ELDORADO LINE THROUGH ITS CONTROL OF DISPATCHES ON THAT LINE BECAUSE SOUTHERN CALIFORNIA EDISON HAS A PARTICIPATING GENERATOR AGREEMENT WITH THE ISO REGARDING THE FOUR CORNERS GENERATING STATION.

A. Dr. Marcus relied upon a response to data request Cities-ISO-12 that the ISO, upon further review, has determined is incorrect. The Four Corners Generating Station is not listed on Schedule 1 of SCE's Participating Generator Agreement ("PGA"), which identifies those Generating Units subject to the provisions of the PGA. Rather, the Four Corners Generating Station is listed as Regulatory Must-Take Generation and is not part of Schedule 1 to the PGA. Regulatory Must-Take Generation is identified by the California Public Utilities Commission, or a local Regulatory Authority, as Generation that the ISO must accept; that is, the ISO has little control over that Generation. Regulatory Must-Take Generation is typically qualifying facilities, nuclear units and existing power purchase contracts. This information was provided to the ISO by SCE simultaneously with an amendment to a revision to SCE's Schedule 1 of its PGA, and the ISO, in preparing the data response, did not appropriately distinguish between Schedule 1 and the list of Regulatory Must-Take Generation.

FIRM TRANSMISSION RIGHTS

Q. WHAT DOES DR. MARCUS SAY ABOUT FTRS?

A. Although he does not misrepresent the function of FTRs, Dr. Marcus contends that the FTRs granted Anaheim and Riverside in connection with the NTS and STS diminish the value of those Entitlements to users of the ISO Controlled Grid.

Q. WHAT ARE FTRS?

A. FTRs were developed by the ISO to provide the functional equivalent of Firm Transmission Rights on the ISO Controlled Grid. Under Article 9 of the ISO Tariff, the ISO makes FTRs available through periodic auctions to enable Market Participants to hedge their exposure to Inter-Zonal Congestion costs imposed through Usage Charges. FTRs entitle the holder to receive a share of the Usage Charge revenues paid to the ISO. Revenues that the ISO receives through the auction of FTRs are distributed to Participating TOs whose transmission facilities and Entitlements together constitute the Inter-Zonal Interfaces for which FTRs are issued.

FTRs also provide FTR holders with a limited Scheduling priority in the Day-Ahead Market. If the FTR is not used in the Day-Ahead Market, or if the FTR holder changes its Schedule subsequent to the Day-Ahead Market, there is no priority.

Q. DO THE FTRS THAT ANAHEIM AND RIVERSIDE RECEIVE IN CONNECTION WITH THE NTS AND STS DIFFER FROM THE FTRS YOU JUST DESCRIBED?

A. No. They provide the same financial hedge and the same limited Scheduling priority.

Q. DO ANAHEIM AND RIVERSIDE PURCHASE THESE FTRS THROUGH THE PERIODIC AUCTION?

A. No. During the negotiations concerning the ISO's Access Charge, representatives of some publicly owned utilities expressed the concern that replacing their Existing Rights, one for one, with FTRs acquired through the ISO's auction or the secondary market would impair their ability to continue to serve their customers economically on a firm basis. The Access Charge proposal adopted by the ISO Governing Board, and approved by the Commission, provided that, during the ten-year transition period (or a shorter period representing the term of an Existing Contract), a New Participating TO that converts Existing Rights to ISO transmission service will receive FTRs represented by those rights directly, without the necessity of participating in the ISO's auction. The procedure appears in Section 9.4.3 of the ISO Tariff. The transition period ends December 31, 2010.

Q. DOESN'T THIS DISCRIMINATE AGAINST EXISTING PARTICIPATING TOS?

A. Yes, but the discrimination is a temporary measure designed to encourage participation in the ISO and the Commission has *specifically* approved it. As Commission Staff noted in its testimony, in the ISO's Transmission Access Charge proceeding in Docket No. ER00-2019-000, the Commission stated:

> Generally, we find that the ISO's proposed treatment of FTRs is reasonable. As explained by the ISO, the proposal to exempt new Participating TOs from the auction process during the transition period is a feature that has been offered as an inducement to encourage participation in the ISO. The proposal will afford the new Participating TOs protection against potential cost increases during the transition period.

Q. HAVE YOU HAD THE OPPORTUNITY TO EXAMINE THE COST IMPACT ON THE ISO'S TRANSMISSION ACCESS CHARGE OF THE INCLUSION OF THE NTS AND THE STS IN ANAHEIM'S AND RIVERSIDE'S TRANSMISSION REVENUE REQUIREMENTS?

A. I have.

Q WHAT ANALYSIS DID YOU PERFORM?

A. I compared the current transmission Access Charge rate effective January 1, 2004 with what the rate would be if the cost of Anaheim's and Riverside's Entitlements in the NTS and STS were subtracted from their Transmission Revenue Requirements at the amounts agreed to in the Southern Cities settlement that has been accepted by the Commission. The analysis is included as Exhibit ISO-3.

Q. WHAT WAS THE RESULT?

A. The inclusion of the NTS and STS increases the transmission Access Charge by $0.25/MWh in the East Central TAC Area and by $0.06/MWh in the North and South TAC Areas.

Q. THANK YOU. I HAVE NO FURTHER QUESTIONS.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Anaheim, California	)	Docket No.	EL03-15-000
City of Riverside, California	)		EL03-20-000

____________________________)
City of Folsom)
County of Sacramento)
State of California)
____________________________)

AFFIDAVIT OF WITNESS

I, Deborah A. Le Vine, being duly sworn, deposes and says that she has read the foregoing questions and answers labeled as her testimony; that if asked the same questions her answers in response would be as shown; and the facts contained in her answers are true and correct to the best of her knowledge, information, and belief.

Executed on this 6th day of April, 2004.

Deborah A Le Vine

Deborah A. Le Vine

Subscribed and sworn to before
me this 6 day of April, 2004.

Virginia B. Davis

Notary Public
State of California

VIRGINIA B. DAVIS
Commission # 1266266
Notary Public - California
Sacramento County
My Comm. Expires Jun 30, 2004

January 1, 2004 TAC Rate
Based on Filed Annual TRR/TRBA and Load Data

TAC Components:

RATE @ 1Jan04	Filed Annual TRR Existing HV Facilities ($) [1]	Filed Annual TRR New HV Facilities ($) [2]	Filed Annual Gross Load (MWh) [3]	TAC Area [4]	Total Filed TRR ($) [5] = [1] + [2]	EHVF only Utility Specific Rate ($/MWH) [6] = [1] / [3]	EHVF only TAC Area Rate ($/MWH) [7] = [21]	HV Utility Specific Rate ($/MWH) [8] = [5] / [3]	TAC Area Rate ($/MWH) [9] = [19]
PG&E	$ 146,199,679	$ 45,188,967	83,389,232	N	$ 191,388,646	$ 1.7532	$ 1.8940	$ 2.2951	$ 2.2191
SCE	$ 173,100,226	$ 7,193,729	84,358,000	EC	$ 180,293,955	$ 2.0520	$ 2.3332	$ 2.1372	$ 2.6583
SDG&E	$ 35,851,531	$ 10,423,518	19,404,874	S	$ 46,275,049	$ 1.8476	$ 1.9506	$ 2.3847	$ 2.2757
Anaheim	$ 22,137,921	$ -	2,589,830	EC	$ 22,137,921	$ 8.5480	$ 2.3332	$ 8.5480	$ 2.6583
Azusa	$ 1,392,585	$ -	239,575	EC	$ 1,392,585	$ 5.8127	$ 2.3332	$ 5.8127	$ 2.6583
Banning	$ 977,914	$ -	139,457	EC	$ 977,914	$ 7.0123	$ 2.3332	$ 7.0123	$ 2.6583
Riverside	$ 16,941,060	$ -	1,814,019	EC		$ 9.3390	$ 2.3332	#VALUE!	$ 2.6583
Vernon	$ 9,990,364	$ -	1,210,668	EC	$ 9,990,364	$ 8.2519	$ 2.3332	$ 8.2519	$ 2.6583
ISO Total	**$ 406,591,280**	**$ 62,806,214**	**193,145,655**		**$ 452,456,433**				

STEP 1: Calculate the Access Charge Rate for each TAC Area.
TAC-Area portion is the percent of Total TRR in each area which has not yet transitioned to the ISO (60%) divided by the Total Load of each area.
The ISO portion is the percent of all TRR which has transitioned to ISO-Wide (40%), plus the TRR of New HV Facilities, divided by total load.

	Annual TRR Existing HV Facilities ($) [10] = [1]	Annual TAC Area TRR ($) [11] = [10] x 60%	Annual Gross Load (GWH) [12] = [3]	TAC Area Rate ($/MWH) [13] = [11] / [12]
North	$ 146,199,679	$ 87,719,808	83,389,232	$ 1.0519
East/C	$ 224,540,070	$ 134,724,042	90,351,549	$ 1.4911
South	$ 35,851,531	$ 21,510,919	19,404,874	$ 1.1085
Total	**$ 406,591,280**	**$ 243,954,768**	**193,145,655**	

	ISO Wide TRR Existing HV Facilities ($) [14] Total ([10]) x 40%	ISO Wide TRR New HV Facilities ($) [15] = Total [2]	ISO Wide Annual Gross Load (GWH) [16] = Total [3]	ISO Wide Rate ($/MWH) [17] = ([14] + [15]) / [16]	EHVF only ISO-Wide Rate ($/MWH) [18] =[14] / [16]
ISO-wide	**$ 162,636,512**	**$ 62,806,214**	**193,145,655**	**$ 1.1672**	**$ 0.8420**

	TAC Rate (TAC Area + ISO Wide) ($/MWH) [19] = [13] + [17]	Wheeling Rate (TAC Area + ISO Wide) ($/MWH) [20] = [19]	Existing HV Facilites (EHVF) only TAC Rate ($/MWH) [21] = [13] + [18]	New HV Facilites (NHVF) only TAC Rate ($/MWH) [22] = [15] / [16]
North	**$ 2.2191**	**$ 2.2191**	$ 1.8940	$ 0.3252
East/Central	**$ 2.6583**	**$ 2.6583**	$ 2.3332	$ 0.3252
South	**$ 2.2757**	**$ 2.2757**	$ 1.9506	$ 0.3252

January 1, 2004 TAC Rate
Based on Filed Annual TRR/TRBA and Load Data

STEP 2: Calculate the HV Access Charge the UDC/MSS pays on Filed Gross Load and Benefit/Burden. Note: ISO total for (Benefit)/Burden may not equal zero due to rounding of TAC Rate.

	TAC Area	Filed Gross Load (MWH)	EHVF only TAC Rate ($/MWH)	Amount Paid Based on Filed Gross Load ($)	EHVF only Utility Specific Rate ($/MWH)	Would Have Paid w/ EHVF Utility Specific Rate ($)	EHVF Access Charge (Benefit)/Burden ($)
	[22] = [4]	[23] = [3]	[24] = [7]	[25] = [23] x [24]	[26] = [6]	[27] = [23] x [26]	[28] = [25] - [27]
PG&E	N	83,389,232	$ 1.8940	$ 157,936,939	$ 1.7532	$ 146,199,679	$ 11,737,260
SCE	EC	84,358,000	$ 2.3332	$ 196,819,878	$ 2.0520	$ 173,100,226	$ 23,719,652
SDG&E	S	19,404,874	$ 1.9506	$ 37,850,613	$ 1.8476	$ 35,851,531	$ 1,999,082
Anaheim	EC	2,589,830	$ 2.3332	$ 6,042,462	$ 8.5480	$ 22,137,921	$ (16,095,459)
Azusa	EC	239,575	$ 2.3332	$ 558,964	$ 5.8127	$ 1,392,585	$ (833,621)
Banning	EC	139,457	$ 2.3332	$ 325,374	$ 7.0123	$ 977,914	$ (652,539)
Riverside	EC	1,814,019	$ 2.3332	$ 4,232,379	$ 9.3390	$ 16,941,060	$ (12,708,682)
Vernon	EC	1,210,668	$ 2.3332	$ 2,824,670	$ 8.2519	$ 9,990,364	$ (7,165,694)
ISO Total		**193,145,655**		**$ 406,591,280**		**$ 406,591,280**	**$ 0**

STEP 3: For Information Only -- Projected annual net benefits/burdens from Access Charge for Existing Facilities.
$32/32/8 million cap for IOUs; munis are held harmless; IOUs pay muni cost increases in proportion to their cap relative to the total cap.

	EHVF Access Charge (Benefit)/Burden ($)	IOU Burden Annual Cap ($)	Amount IOUs' Cap Exceeds IOUs' Burden ($)	Amount IOU's Burden Exceeds IOU's Cap ($)	Payments by Entities with Net Benefit ($)	Mitigation Payments ($)	Adjusted Net (Benefit) / Burden ($)	Reallocation IOU Burden ($)	Transition Charge ($)	Adjusted Net (Benefit) / Burden ($)	Transition Charge Rate ($/MWh)
	[29] = [28]	[30]	[31] IF ([30] - [29] >0) = [30] - [29]. If no cap, then 0.	[32] IF [29] - [30] >0 = [29] - [30]. If no cap, then 0.	[33] IOUs = ([31] / total[31]) x total[32]. Munis w/ Benefit= ([29] / total[29]) x total[32] - total[31]	[34] = [33] - [32]	[35] = [29] + [34]	[36] Reallocate IOU Burden [38] so it is proportional to IOU Cap [30] = [38] - [35]	[37] = [34] + [36]	[38] = [35] + [36]	[39] = [37] / [23]
PG&E	$ 11,737,260	$ 32,000,000	$ 20,262,740	$ 0	$ 0	$ 0	$ 11,737,260	$ 4,909,849	$ 4,909,849	$ 16,647,109	$ 0.0589
SCE	$ 23,719,652	$ 32,000,000	$ 8,280,348	$ 0	$ 0	$ 0	$ 23,719,652	$ (7,072,544)	$ (7,072,544)	$ 16,647,109	$ (0.0838)
SDG&E	$ 1,999,082	$ 8,000,000	$ 6,000,918	$ 0	$ 0	$ 0	$ 1,999,082	$ 2,162,695	$ 2,162,695	$ 4,161,777	$ 0.1115
Anaheim	$ (16,095,459)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (16,095,459)	$ 0	$ 0	$ (16,095,459)	$ 0
Azusa	$ (833,621)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (833,621)	$ 0	$ 0	$ (833,621)	$ 0
Banning	$ (652,539)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (652,539)	$ 0	$ 0	$ (652,539)	$ 0
Riverside	$ (12,708,682)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (12,708,682)	$ 0	$ 0	$ (12,708,682)	$ 0
Vernon	$ (7,165,694)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (7,165,694)	$ 0	$ 0	$ (7,165,694)	$ 0
Total	**$ 0**	**$ 72,000,000**	**$ 34,544,006**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	

STEP 4: For Information Only -- Projected annual net benefits/burdens from Access Charge for New Facilities and Total projected annual net benefits/burdens from Access Charge.

	Filed Annual TRR New HV Facilities ($)	ISO Wide Annual Gross Load (MWh)	New HVTRR Rate ($/MWH)	New HVTRR Cost Responsibility ($)	NHVF Access Charge (Benefit)/Burden ($)	Total Access Charge (Benefit)/Burden ($)
	[40] = [2]	[41] = [3]	[42] = ([15]) / [16]	[43] = ([42]) * [43]	[44] = ([42]) - [40]	[45] = ([44]) + [38]
PG&E	$ 45,188,967	83,389,232	$ 0.3252	$ 27,116,126	$ (18,072,841)	$ (1,425,732)
SCE	$ 7,193,729	84,358,000	$ 0.3252	$ 27,431,146	$ 20,237,417	$ 36,884,525
SDG&E	$ 10,423,518	19,404,874	$ 0.3252	$ 6,309,987	$ (4,113,531)	$ 48,247
Anaheim	$ -	2,589,830	$ 0.3252	$ 842,149	$ 842,149	$ (15,253,310)
Azusa	$ -	239,575	$ 0.3252	$ 77,904	$ 77,904	$ (755,717)
Banning	$ -	139,457	$ 0.3252	$ 45,348	$ 45,348	$ (607,191)
Riverside	$ -	1,814,019	$ 0.3252	$ 589,874	$ 589,874	$ (12,118,807)
Vernon	$ -	1,210,668	$ 0.3252	$ 393,679	$ 393,679	$ (6,772,014)
Total	**$ 62,806,214**	**193,145,655**		**$ 62,806,214**	**$ (0)**	**$ 0**

January 1, 2004 TAC Rate
Based on Filed Annual TRR/TRBA and Load Data
RATES WITHOUT NTS/STS FOR ANAHEIM AND RIVERSIDE

TAC Components:

RATE @ 1Jan04	Filed Annual TRR Existing HV Facilities ($) [1]	Filed Annual TRR New HV Facilities ($) [2]	Filed Annual Gross Load (MWh) [3]	TAC Area [4]	Total Filed TRR ($) [5] = [1] + [2]	EHVF only Utility Specific Rate ($/MWH) [6] = [1] / [3]	EHVF only TAC Area Rate ($/MWH) [7] = [21]	HV Utility Specific Rate ($/MWH) [8] = [5] / [3]	TAC Area Rate ($/MWH) [9] = [19]
PG&E	$ 146,199,679	$ 45,188,967	83,389,232	N	$ 191,388,646	**$ 1.7532**	**$ 1.8340**	**$ 2.2951**	**$ 2.1591**
SCE	$ 173,100,226	$ 7,193,729	84,358,000	EC	$ 180,293,955	**$ 2.0520**	**$ 2.0807**	**$ 2.1372**	**$ 2.4059**
SDG&E	$ 35,851,531	$ 10,423,518	19,404,874	S	$ 46,275,049	**$ 1.8476**	**$ 1.8906**	**$ 2.3847**	**$ 2.2157**
Anaheim	$ 3,772,921	$ -	2,589,830	EC	$ 3,772,921	**$ 1.4568**	**$ 2.0807**	**$ 1.4568**	**$ 2.4059**
Azusa	$ 1,392,585	$ -	239,575	EC	$ 1,392,585	**$ 5.8127**	**$ 2.0807**	**$ 5.8127**	**$ 2.4059**
Banning	$ 977,914	$ -	139,457	EC	$ 977,914	**$ 7.0123**	**$ 2.0807**	**$ 7.0123**	**$ 2.4059**
Riverside	$ 6,329,060	$ -	1,814,019	EC	$ 6,329,060	**$ 3.4890**	**$ 2.0807**	**$ 3.4890**	**$ 2.4059**
Vernon	$ 9,990,364	$ -	1,210,668	EC	$ 9,990,364	**$ 8.2519**	**$ 2.0807**	**$ 8.2519**	**$ 2.4059**
ISO Total	**$ 377,614,280**	**$ 62,806,214**	**193,145,655**		**$ 440,420,494**				

STEP 1: Calculate the Access Charge Rate for each TAC Area.
TAC-Area portion is the percent of Total TRR in each area which has not yet transitioned to the ISO (60%) divided by the Total Load of each area.
The ISO portion is the percent of all TRR which has transitioned to ISO-Wide (40%), plus the TRR of New HV Facilities, divided by total load.

	Annual TRR Existing HV Facilities ($) [10] = [1]	Annual TAC Area TRR ($) [11] = [10] x 60%	Annual Gross Load (GWH) [12] = [3]	TAC Area Rate ($/MWH) [13] = [11] / [12]
North	$ 146,199,679	$ 87,719,808	83,389,232	$ 1.0519
East/C	$ 195,563,070	$ 117,337,842	90,351,549	$ 1.2987
South	$ 35,851,531	$ 21,510,919	19,404,874	$ 1.1085
Total	**$ 377,614,280**	**$ 226,568,568**	**193,145,655**	

	ISO Wide TRR Existing HV Facilities ($) [14] Total ([10]) x 40%	ISO Wide TRR New HV Facilities ($) [15] = Total [2]	ISO Wide Annual Gross Load (GWH) [16] = Total [3]	ISO Wide Rate ($/MWH) [17] = ([14] + [15]) / [16]	EHVF only ISO-Wide Rate ($/MWH) [18] =[14] / [16]
ISO-wide	**$ 151,045,712**	**$ 62,806,214**	**193,145,655**	**$ 1.1072**	**$ 0.7820**

	TAC Rate (TAC Area + ISO Wide) ($/MWH) [19] = [13] + [17]	Wheeling Rate (TAC Area + ISO Wide) ($/MWH) [20] = [19]	Existing HV Facilites (EHVF) only TAC Rate ($/MWH) [21] = [13] + [18]	New HV Facilites (NHVF) only TAC Rate ($/MWH) [22] = [15] / [16]
North	**$ 2.1591**	**$ 2.1591**	$ 1.8340	$ 0.3252
East/Central	**$ 2.4059**	**$ 2.4059**	$ 2.0807	$ 0.3252
South	**$ 2.2157**	**$ 2.2157**	$ 1.8906	$ 0.3252

January 1, 2004 TAC Rate
Based on Filed Annual TRR/TRBA and Load Data
RATES WITHOUT NTS/STS FOR ANAHEIM AND RIVERSIDE

STEP 2: Calculate the HV Access Charge the UDC/MSS pays on Filed Gross Load and Benefit/Burden. Note: ISO total for (Benefit)/Burden may not equal zero due to rounding of TAC Rate.

	TAC Area	Filed Gross Load (MWH)	EHVF only TAC Rate ($/MWH)	Amount Paid Based on Filed Gross Load ($)	EHVF only Utility Specific Rate ($/MWH)	Would Have Paid w/ EHVF Utility Specific Rate ($)	EHVF Access Charge (Benefit)/Burden ($)
	[22] = [4]	[23] = [3]	[24] = [7]	[25] = [23] x [24]	[26] = [6]	[27] = [23] x [26]	[28] = [25] - [27]
PG&E	N	83,389,232	$ 1.8340	$ 152,932,695	$ 1.7532	$ 146,199,679	$ 6,733,016
SCE	EC	84,358,000	$ 2.0807	$ 175,524,627	$ 2.0520	$ 173,100,226	$ 2,424,401
SDG&E	S	19,404,874	$ 1.8906	$ 36,686,114	$ 1.8476	$ 35,851,531	$ 834,583
Anaheim	EC	2,589,830	$ 2.0807	$ 5,388,688	$ 1.4568	$ 3,772,921	$ 1,615,767
Azusa	EC	239,575	$ 2.0807	$ 498,486	$ 5.8127	$ 1,392,585	$ (894,099)
Banning	EC	139,457	$ 2.0807	$ 290,170	$ 7.0123	$ 977,914	$ (687,744)
Riverside	EC	1,814,019	$ 2.0807	$ 3,774,449	$ 3.4890	$ 6,329,060	$ (2,554,611)
Vernon	EC	1,210,668	$ 2.0807	$ 2,519,050	$ 8.2519	$ 9,990,364	$ (7,471,314)
ISO Total		**193,145,655**		**$ 377,614,280**		**$ 377,614,280**	**$ (0)**

STEP 3: For Information Only -- Projected annual net benefits/burdens from Access Charge for Existing Facilities.
$32/32/8 million cap for IOUs; munis are held harmless; IOUs pay muni cost increases in proportion to their cap relative to the total cap.

	EHVF Access Charge (Benefit)/Burden ($)	IOU Burden Annual Cap ($)	Amount IOUs' Cap Exceeds IOUs' Burden ($)	Amount IOU's Burden Exceeds IOU's Cap ($)	Payments by Entities with Net Benefit ($)	Mitigation Payments ($)	Adjusted Net (Benefit) / Burden ($)	Reallocation IOU Burden ($)	Transition Charge ($)	Adjusted Net (Benefit) / Burden ($)	Transition Charge Rate ($/MWh)
	[29] = [28]	[30]	[31] IF ([30] - [29] >0) = [30] - [29]. If no cap, then 0.	[32] IF [29] - [30] >0 = [29] - [30]. If no cap, then 0.	[33] IOUs = ([31] / total[31]) x total[32]. Munis w/ Benefit= ([29] / total[29]) x total[32] - total[31]	[34] = [33] - [32]	[35] = [29] + [34]	[36] Reallocate IOU Burden [38] so it is proportional to IOU Cap [30] = [38] - [35]	[37] = [34] + [36]	[38] = [35] + [36]	[39] = [37] / [23]
PG&E	$ 6,733,016	$ 32,000,000	$ 25,266,984	$ 0	$ 658,392	$ 658,392	$ 7,391,408	$ (2,232,400)	$ (1,574,009)	$ 5,159,007	$ (0.0189)
SCE	$ 2,424,401	$ 32,000,000	$ 29,575,599	$ 0	$ 770,663	$ 770,663	$ 3,195,064	$ 1,963,943	$ 2,734,607	$ 5,159,007	$ 0.0324
SDG&E	$ 834,583	$ 8,000,000	$ 7,165,417	$ 0	$ 186,712	$ 186,712	$ 1,021,295	$ 268,457	$ 455,169	$ 1,289,752	$ 0.0235
Anaheim	$ 1,615,767	$ 0	$ 0	$ 1,615,767	$ 0	$ (1,615,767)	$ 0	$ 0	$ (1,615,767)	$ 0	$ (0.6239)
Azusa	$ (894,099)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (894,099)	$ 0	$ 0	$ (894,099)	$ 0
Banning	$ (687,744)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (687,744)	$ 0	$ 0	$ (687,744)	$ 0
Riverside	$ (2,554,611)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (2,554,611)	$ 0	$ 0	$ (2,554,611)	$ 0
Vernon	$ (7,471,314)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (7,471,314)	$ 0	$ 0	$ (7,471,314)	$ 0
Total	**$ 0**	**$ 72,000,000**	**$ 62,008,000**	**$ 1,615,767**	**$ 1,615,767**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	

STEP 4: For Information Only -- Projected annual net benefits/burdens from Access Charge for New Facilities and Total projected annual net benefits/burdens from Access Charge.

	Filed Annual TRR New HV Facilities ($)	ISO Wide Annual Gross Load (MWh)	New HVTRR Rate ($/MWH)	New HVTRR Cost Responsibility ($)	NHVF Access Charge (Benefit)/Burden ($)	Total Access Charge (Benefit)/Burden ($)
	[40] = [2]	[41] = [3]	[42] = ([15]) / [16]	[43] = ([42]) * [43]	[44] = ([42]) - [40]	[45] = ([44]) + [38]
PG&E	$ 45,188,967	83,389,232	$ 0.3252	$ 27,116,126	$ (18,072,841)	$ (12,913,833)
SCE	$ 7,193,729	84,358,000	$ 0.3252	$ 27,431,146	$ 20,237,417	$ 25,396,424
SDG&E	$ 10,423,518	19,404,874	$ 0.3252	$ 6,309,987	$ (4,113,531)	$ (2,823,779)
Anaheim	$ -	2,589,830	$ 0.3252	$ 842,149	$ 842,149	$ 842,149
Azusa	$ -	239,575	$ 0.3252	$ 77,904	$ 77,904	$ (816,195)
Banning	$ -	139,457	$ 0.3252	$ 45,348	$ 45,348	$ (642,396)
Riverside	$ -	1,814,019	$ 0.3252	$ 589,874	$ 589,874	$ (1,964,736)
Vernon	$ -	1,210,668	$ 0.3252	$ 393,679	$ 393,679	$ (7,077,634)
Total	**$ 62,806,214**	**193,145,655**		**$ 62,806,214**	**$ (0)**	**$ 0**

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Anaheim, California	)	Docket Nos. EL03-15-000
	)	
City of Riverside, California	)	EL03-20-000

PREPARED DIRECT TESTIMONY OF
ZIAD ALAYWAN
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Anaheim, California	)	Docket Nos. EL03-15-000
	)	
City of Riverside, California	)	EL03-20-000

SUMMARY OF CROSS-ANSWERING TESTIMONY OF
ZIAD ALAYWAN
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Mr. Alayawn explains that the ISO network model used currently for congestion management is composed of radially connected congestion zones as the result of consensus among the many stakeholders in the ISO formation. Simplicity and transparency thus favored a zonal congestion management system.The zonal model only considered major congestion bottlenecks at Path 15 and several inter-ties with external control areas and separated the system to radially connected zones. Scheduling restrictions that may arise because of Scheduling limitations on one segment of a branch group.

The Scheduling restrictions on the NTS and STS arise because of a number of factors. The NTS and STS are not, however, the only branch groups with such Scheduling restrictions.

in cooperation with the Commission and stakeholders, the ISO has undertaken a multiyear market redesign process know as MD02. In MD02 Phase-3, the CAISO will implement an integrated forward energy and ancillary services market.. The market applications in MD02 Phase-3 will use a Full Network Model (FNM), which is a detailed network model for the ISO grid, expanded to include external Scheduling Points connected to the ISO grid through a radial network of tie-lines. The proposed model will provide more scheduling flexibility, more effective congestion management, and more accurate Locational Marginal Pricing.

Mr. Alaywan also explains that the scheduling priority provided to Anaheim and Riverside at IPP is neither discriminatory nor unique.

Finally, Mr. Alaywan examines the usage of the NTS and STS compared to other transmission lines. He concludes the New Participating TOs do not make greater use of the transmission lines that they place under ISO Operational Control that the Original Participating TOs make of transmission lines they place under the ISO's Operational Control.

Q PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A My name is Ziad Alaywan. I am the Director Of Market Operations for the California ISO. My business address is 151 Blue Ravine Rd., Folsom, California 95762.

Q HAVE YOU HELD PREVIOUS POSITIONS AND RESPONSIBILTIES WITH THE ISO?

A Yes, I have previously held the positions of Manager of Operations and Director Of Operations Engineering and Maintenance.

Q PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A I have more than 16 years of experience in the energy sector, electric system operations, restructuring, market design and implementation. In my current position as Director of Market Operations at the California ISO, I oversee the implementation and the operation of the day ahead, hour ahead and real time markets. This includes operation of the Ancillary Services, Congestion Management, Energy spot Markets, network modeling, and Firm Transmission Rights ("FTR") auction. I was one of the first employees hired by the ISO in June 1997 and was instrumental in start-up of the pioneering organization with responsibility to implement and operate the ISO markets. Prior to the formation of the California ISO, I was working for the ISO trustees and led the effort in putting together the new organization, focused on development and implementation of the bidding, Scheduling and pricing systems.

Prior to my experience at the ISO, I worked at Pacific Gas & Electric in various positions in system operations, real-time Dispatch, power plant operation, and transmission planning. From 1993-1996, I supervised the real-time operations of PG&E Generation, transmission, and Scheduling. I received Bachelor and Master's degrees in Electrical Engineering from Montana State University in 1987. I am also a certified Professional Engineer in the State of California. I completed an Executive Management program at the Haas school of Business, University of California, Berkeley, California, 2002.

Q HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A No.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A As discussed in the testimony of Ms. Le Vine, I will provide information in response to four areas of the testimony of Dr. David Marcus: Scheduling restrictions on the NTS and STS; the impact of the ISO's market redesign on those Scheduling restrictions; whether Anaheim and Riverside have discriminatory access to the NTS and STS; and Anaheim's and Riverside's usage of the NTS and STS in comparison with other utilities' usage of their entitlements.

<u>SCHEDULING RESTRICTIONS ON THE NTS AND STS</u>

Q WHAT IS THE ISO'S NETWORK METHODOLOGY?

A The ISO network model used currently for Congestion Management is composed of radially connected Congestion Zones. Congestion management is performed in the forward markets only on the Inter-Zonal interfaces between Congestion Zones. Intra-zonal Congestion mitigation takes place in real time through out-of-sequence Dispatch instructions. As a result of this zonal Congestion Management, the marginal Congestion price between any two Congestion Zones in the forward markets does not depend on the particular locations of the Schedule sources or sinks within the relevant Congestion Zones. Similarly, the ex post imbalance Energy price is uniform within a given Congestion Zone.

Q WHY DID THE ISO ADOPT THIS METHODOLOGY?

A The ISO implemented this methodology as the result of consensus among the many stakeholders in the ISO formation. Operational experience (from the utilities at that time) indicated that Intra-Zonal Congestion was infrequent and inexpensive. Simplicity and transparency thus favored a zonal Congestion Management system.

Q WHY THE ISO ADOPT A RADIAL BRANCH GROUP METHODOLOGY FOR INTER-ZONAL SCHEDULING AND CONGESTION MANAGEMENT?

A Consistent with this goal of simplicity and transparency , the zonal model only considered major Congestion bottlenecks at Path 15 and several inter-ties with external control areas. These constraint paths, the branch groups, separated the system into radially connected Zones. This resulted in transparent Congestion prices that were independent from Schedule source and sink locations within Congestion Zones, and transparent ex post imbalance Energy prices that were uniform within a given Congestion Zone. Path 26, another constraint path that was later added to the list, maintained the radial zonal configuration and the transparency in Congestion and ex post prices. At the time, these advantages suggested that this would be a reasonable approach to Congestion Management.

Q ARE ALL THE BRANCH GROUPS RADIAL?

A Yes. The internal branch groups, Path 15 and Path 26, are radial Inter-Zonal interface connections between Congestion Zones. The inter-ties with external control areas are also radial to be consistent with WECC Scheduling practices where imports to and exports from the ISO are Scheduled individually at each inter-tie, rather than as a net interchange.

Q HAVE THERE TURNED OUT TO BE DRAWBACKS ASSOCIATED WITH THE RADIAL BRANCH GROUP MODEL THE ISO HAS USED?

A Yes. Of particular concerns for this proceeding are Scheduling restrictions that may arise because of Scheduling limitations on one segment of a branch group. The Scheduling restrictions imposed on the NTS and STS are described in Commission Staff testimony. It is my understanding that Scheduling restrictions on the NTS and STS have been a contentious issue in this proceeding.

Q WHAT IS THE REASON FOR THE SCHEDULING RESTRICTIONS ON THE NTS AND STS?

A These restriction arise because of a number of factors. All the Energy from NTS and STS must flow on STS; therefore its Operating Transmission Capacity

("OTC") is the limiting factor. The available STS capacity is 534 MW. The STS OTC is divided between the IPP, the Mona, and the Gonder OTCs so that each can be represented as though it were a single Branch Group with its own individual OTC. This allows the ISO to fix curtailments to the right segment and to apply necessary management to the individual points. Since the only Energy that can be injected at IPP is IPP Generation, the IPP Branch Group OTC capacity is established to allow the Generation Schedules into ISO, the remainder of the 534 MW STS rating is distributed between Mona and Gonder OTC capacities.

The three branch groups form essentially a "T" shaped transmission system. In contrast to the Eldorado Branch Group, which puts Four Corners, Moenkopi, and Eldorado Schedules into one total OTC, the STS/NTS group is divided into separate branch groups with their own individual OTCs. Perhaps IPP could have been treated as one branch group with one total, but the ISO determined that it would be too hard to manage because the ISO could not control the redistribution of OTC when there is a curtailment. The prime restriction on the Schedules is the capacity of the STS (534 MW), which is distributed for maximum efficiency among the three branch groups (Mona, Gonder, IPP). The limitations of the ISO Congestion Management model limited us from letting some branch groups in the Mead-Phoenix system connect to each other.

Q WERE THERE OTHER FACTORS THAT RESTRICTED SCHEDULES ON THE NTS AND STS?

A Yes, although only some of those factors restricted Schedules beyond what might have been possible prior to Anaheim and Riverside becoming Participating TOs. The restriction against exporting at IPP is that there is no take-out there (no Load) plus the interpretation of rights at the time of implementation was that there was no provision in the agreements being converted for south to north Schedules on the STS. The restriction against exports at Mona is strictly due to the interpretation of the rights at the time of implementation. The restriction against exports at Gonder resulted from an effort to simplify the system as much as possible in order to make the implementation as soon as possible. The implementation would have further complicated efforts to manually monitor the inadmissible Schedules, and wouldn't have offered much immediately appreciable New Firm Use, so it was postponed for later consideration. Some restrictions are due to line capacity, some are due to contract limitations, some are due to the balance between simplicity and utility.

Q BESIDES SCHEDULING RESTRICTIONS, ARE THERE OTHER DRAWBACKS ASSOCIATED WITH THE CHOSEN MODEL?

A Yes, these include for example the following:

- The radial inter-ties ignore alternate transmission paths into the ISO, such as the Mead 500/230 kV transformer followed by the Mead 230 kV transmission line to El Dorado 230 kV, or the Marketplace-McCullough-El Dorado 500 kV lines. This artificially restricts the import capability from the new Scheduling Points into the ISO.

- Import Schedules from the new Scheduling Points into the ISO are not possible when any network link in the transmission path to Lugo 500 kV is out of service. For example, the outage of the Marketplace-Adelanto 500 kV line will prohibit import Schedules from Marketplace 500 kV or Westwing 500 kV. If the Victorville-Lugo 500 kV line is out, no import Schedule is possible from any of the new Scheduling Points.
- Wheeling transactions between the new Scheduling Points must be Scheduled as matching imports into and exports out of the ISO. This is unnecessary complication and it requires manual Scheduling workaround when the Victorville-Lugo 500 kV line is out.
- The new zero-impedance inter-ties do not account for transmission losses, which requires a separate calculation for the Tie Meter Multipliers (TMMs) at the new Scheduling Points by adding fixed percentages to the Victorville 500 kV TMM.

Q ARE THE NTS AND STS THE ONLY BRANCH GROUP ON WHICH THE ISO'S NETWORK MODEL RESULTS IN SCHEDULING RESTRICTIONS?

A No. For example, Generation at Four Corners affects Scheduling capacity on Moenkopi-Four Corners; Diablo Canyon and Helms affect Path 15; and there are restrictions on Path 26. The Eldorado Branch Group capacity is 1,555 MW maximum, but is reduced to 740 MW when Unit 5 is off line. The Path 15 Branch Group capacity is 3,950 MW maximum, but is reduced for Diablo or Helms limitations or with northern Generation limitations. The Path 26 Branch Group capacity is 3,000 MW maximum but is also affected by other Generation factors.

Q WITH THESE DRAWBACKS, WHY DID THE ISO MODEL THE NTS AND STS AS IT DID?

A As discussed above, many of the restrictions furthered simplicity and expedited the availability of the new capacity. After full consideration, the ISO and the new

PTO's determined that the current model for the NTS and STS best fit the ISO's existing branch group network model and the software developed to accommodate that model. This ensured consistency with the rest of the inter-ties and the WECC rules.

MARKET REDESIGN

Q IS THE ISO TAKING ANY ACTION TO ADDRESS THE DRAWBACKS OF ITS CURRENT NETWORK MODEL?

A Yes, in cooperation with the Commission and stakeholders, the ISO has undertaken a multiyear market redesign process know as MD02. In MD02 Phase 3, the CAISO will implement an integrated forward Energy and Ancillary Services market. The market applications in MD02 Phase-3 will use a Full Network Model (FNM), which is a detailed network model for the ISO grid, expanded to include external Scheduling Points connected to the ISO grid through a radial network of tie-lines. Exhibit ISO-9 shows the proposed network model extension in the FNM to represent the New PTO transmission rights in MD02 Pase-3. This network model is based on the physical network, but without the Mead 500/230 kV transformer and with a normally open switch on the Marketplace-McCullough 500 kV transmission line. These changes are necessary for a radial tie-line network of Scheduling Points.

Q WILL THE TIE-LINES STILL BE MODELLED RADIALLY?

A Yes. This is the most reasonable approach. A radial inter-tie model ignores loop flow in the ISO Controlled Grid from ISO Schedules due to external network parallel paths, and also loop flows from WECC Schedules that do not involve the ISO. The effects of that loop flow on the transfer capability of a particular path depend on the direction of the loop flow in comparison with the net Schedule direction on that path, which in turn depend on the Generation and Load patterns throughout the WECC and the conditions of the inter-connected network. Nevertheless, WECC Scheduling rules prohibit using unScheduled loop flow in a counter flow direction to increase the transfer capability of a WECC path. Therefore, the effect of considering loop flows in Scheduling and Dispatch can only be detrimental to the available power transfer capability. Consequently, the current radial inter-tie model, also referred to as the "open loop model," results in aggressive Scheduling, i.e., it maximizes the potential transfer capability available for Scheduling. The FNM may include an external network equivalent to model loop flow in the distant future after Scheduling agreements with external control areas are appropriately revised and adequate Scheduling information becomes available to determine loop flow with reasonable accuracy.

Q IF BOTH MODELS ARE RADIAL, WHAT IS THE ADVANTAGE OF THE NEW APPROACH?

A Under MD02, as currently proposed, the network would be expanded to include external Scheduling Points. Multiple Scheduling Points would be interconnected to the ISO Controlled Grid in a fashion consistent with the actual transmission network. The proposed model will provide more Scheduling flexibility, more effective Congestion Management, and more accurate Locational Marginal

Pricing.

Since the proposed tie-line network is radial, it can be added to the current radial zonal network model used by the ISO's software without many modifications. The only problem is that the Ancillary Services procurement application cannot handle Ancillary Services bids from Scheduling Points not directly connected to the CAISO grid through an inter-tie. Therefore, Ancillary Services bids would only be supported at Victorville 500 kV or at McCullough 500 kV. Incorporating the proposed tie-line network model in the current system would allow Market Participants to take advantage of the increased Scheduling flexibility and accuracy that it provides before the MD02 Phase-3 implementation. Thus, once LMP is in place, a Scheduling Coodrinator can Schedule from Gonder to Mona and will be charged for Congestion and losses accordingly.

Q ARE THERE OTHER SPECIFIC ADVANTAGES OF THE MD02 MODEL?

A Yes. They include the following:

- The full New PTO contractual rights can be represented on the radial tie-line network since Congestion Management will be performed by the market applications on all network branches of the FNM, including these tie-lines individually.
- Mead 500 kV can be used as an additional Scheduling Point.
- Wheeling transactions between Scheduling Points can be Scheduled directly (e.g., a wheeling Schedule from Gonder to Mona).
- In the event of an outage on the Victorville-Lugo 500 kV line, the switch on the Marketplace-McCullough 500 kV line can be closed to allow for an alternate transmission path for imports into the CAISO grid through the McCullough-El Dorado 500 kV inter-tie.

- The actual transmission lines can be used in the network model with their physical line parameters, including resistance, thereby providing an automatic and accurate way for considering transmission losses (the marginal cost of losses will be a component of the LMP). The only exception is the IPP-Adelanto ±500 kV HVDC link, which can be replaced by an equivalent AC transmission line with appropriate resistance to simulate the associated DC losses.

- The Scheduling rule of WAPA where netting of Schedules on the Westwing-Marketplace 500 kV transmission path is not allowed can be enforced by splitting each of the Mead 500 kV and Westwing 500 kV buses to two separate buses on two parallel Westwing-Marketplace 500 kV transmission paths. In this way, import and export constraints on the Marketplace-Mead and Mead-Westwing 500 kV transmission lines can be separated, effectively prohibiting netting of import and export Schedules.

DISCRIMINATORY ACCESS

Q DR. MARCUS SUGGESTS THAT BETWEEN CAPACITY RESERVED FOR THE LUGO IPP BRANCH GROUP AND FTRS, ANAHEIM AND RIVERSIDE HAVE DISCRIMINATORY ACCESS TO THE NTS AND STS. DO YOU AGREE?

A No. As Ms. Le Vine explains, Anaheim and Riverside are entitled to the FTRs under the ISO Tariff.

Q ISN'T IT TRUE, HOWEVER, THAT ONLY ANAHEIM AND RIVERSIDE CAN SCHEDULE AT IPP?

A Yes, but that is not an indication that Market Participants are deprived of the use of the NTS or STS. There is no Load at IPP, so it cannot be a take out point for exports. Schedules through IPP will use the Lugo, Gonder and Mona Scheduling points. The only ISO import that could be Scheduled at IPP would be Energy from the Intermountain Generating Station, and only Anaheim and Riverside have entitlement to that Energy.

Q IS THIS CIRCUMSTANCE UNIQUE?

A No. Similar circumstances exist with regarding to Southern California's rights at Four Corners.

USAGE OF THE NTS AND STS

Q IT HAS BEEN SUGGESTED THAT ANAHEIM AND RIVERSIDE SHOULD NOT BE ALLOWED TO INCLUDE THE ENTIRE REVENUE REQUIREMENT FOR THE NTS AND STS IN THEIR TRANSMISSION REVENUE REQUIREMENTS BECAUSE THEY ARE THE PREDOMINANT USERS OF THE NTS AND STS. HAVE YOU ANALYZED HOW THE NEW PARTICIPATING TOS' USAGE OF THEIR FACILITIES COMPARES WITH OTHER UTILITIES USAGE OF SIMILARLY SITUATED TRANSMISSION FACILITIES?

A Yes. Two examples are STS and NTS, the California Oregon Intertie ("COI") and Palo Verde. Before the ISO went operational, Pacific Gas & Electric Company ("PG&E"), SCE and San Diego Gas & Electric Company ("SDG&E") had 1,150 MW, 989 MW and 161 MW of rights on COI, respectively. Prior to ISO operation, SCE had 1,172 MW of rights from Palo Verde to the Devers switchyard in the summer months (April 1 to October 31) and 1,147 MW of rights from Palo Verde to the Devers switchyard in the winter months (November 1 to March 31) and SDG&E had 970 MW of rights from Palo Verde to the North Gila switchyard. I examined the utilities' use of those facilities.

Q WHAT WAS THE UTILITIES' USE OF THESE FACILITIES?

A Table 1 in Exhibit ISO-10 provides monthly aggregate Day-ahead Schedules for the year of 2003 for PG&E, SCE and SDG&E for the COI and Palo Verde Branch Groups. SDG&E did not Schedule on COI for the year of 2003 and thus is not explicitly shown, as well, PG&E did not Schedule on Palo Verde for the year of 2003 and thus is not explicitly shown

Q HOW DID YOU COMPARE THE NEW PARTICIPATING TOS' USE OF THEIR FACILITIES?

A Table 2 provides utilization percentages by PG&E, SCE and SDG&E on COI and Palo Verde. The utilization factor takes into account the rights that PG&E, SCE and SDG&E had on these transmission interfaces prior to ISO operation. Since SDG&E did not Schedule on COI for the year 2003, there is no utilization factor presented. Since PG&E did not Schedule on Palo Verde for the year 2003, there is no utilization factor presented. The utilization factor for a given month per branch group per entity is defined as (Monthly aggregate Schedule) / (rights * days in month * 24 hours in a day). As an example, for the month of February SCE has original rights on Palo Verde of 1,147 MW. The Utilization would be (452,181) / (1,147 * 28 * 24) = 58.7%. where 452,181 MWh is from Table 1 for SCE on the Palo Verde Branch Group for the month of February. There are 28 days in February and thus 28 * 24 = 672 hours in February. The February aggregate amount of the previous rights on Palo Verde for SCE would be 1,147 * 672 = 770,784 MWh.

Table 3 holds the utilization percentages for Schedules across 4 of the newly added branch groups that are part of the new transmission from the new Participating TOs. The data includes the Schedules for the 5 new PTOs (i.e., the Munis) and all other Schedules (i.e., Non-Munis) summed over each month of 2003. The table provides the utilization factor for the muni's Schedule. This utilization factor is calculated by dividing the monthly aggregated Muni Schedule by the total muni rights for that branch group aggregated over each month. The total muni rights over each branch group are 370 MW for Lugo-IPP; 360 MW for LUGO-Marketplace; 160 MW for Lugo-Mona; and 93 MW for Lug0-Westwing. For example, for the Lugo-Marketplace Branch Group (LUGOMKTPC_BG) for March, the total muni Schedule is 10,480 MW and the total rights over this branch group over the month of March is (31 * 24 * 247) = 183,768 MWh. The utilization factor is 13,879/183,768 = 5.7%.

Q WHAT WERE THE RESULTS OF YOUR COMPARISON?

A The data show that although PG&E pays for Palo Verde through the Access Charge, it does not Schedule at Palo Verde; similarly, SDG&E pays for COI through the Access Charge but does not Schedule at COI. Based on the data in Table 2, SCE uses on average 70% (sum of the monthly utilization percentages divided by 12 months) of Palo Verde transmission based on their rights prior to the start of the ISO. The SCE usage on Palo Verde in comparison with their old rights is similar to the new Participating TO's (Anaheim, Riverside, Azusa, Banning and Vernon) usage of their transmission . SCE. In fact, SCE is

Scheduling a higher percentage on Palo Verde than the new PTO's Schedule on their new facilities.

Q THANK YOU. I HAVE NO MORE QUESTIONS.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Anaheim, California City of Riverside, California	))	Docket No. EL03-15-000 EL03-20-000

City of Folsom)
County of Sacramento)
State of California)

AFFIDAVIT OF WITNESS

I, Ziad Alaywan, being duly sworn, deposes and says that he has read the foregoing questions and answers labeled as his testimony; that if asked the same questions his answers in response would be as shown; and the facts contained in his answers are true and correct to the best of his knowledge, information, and belief.

Executed on this 6th day of April, 2004.

Ziad Alaywan

Ziad Alaywan

Subscribed and sworn to before me this 6th day of April, 2004.

VIRGINIA B. DAVIS
Commission # 1266266
Notary Public - California
Sacramento County
My Comm. Expires Jun 30, 2004

Virginia B. Davis

Notary Public
State of California

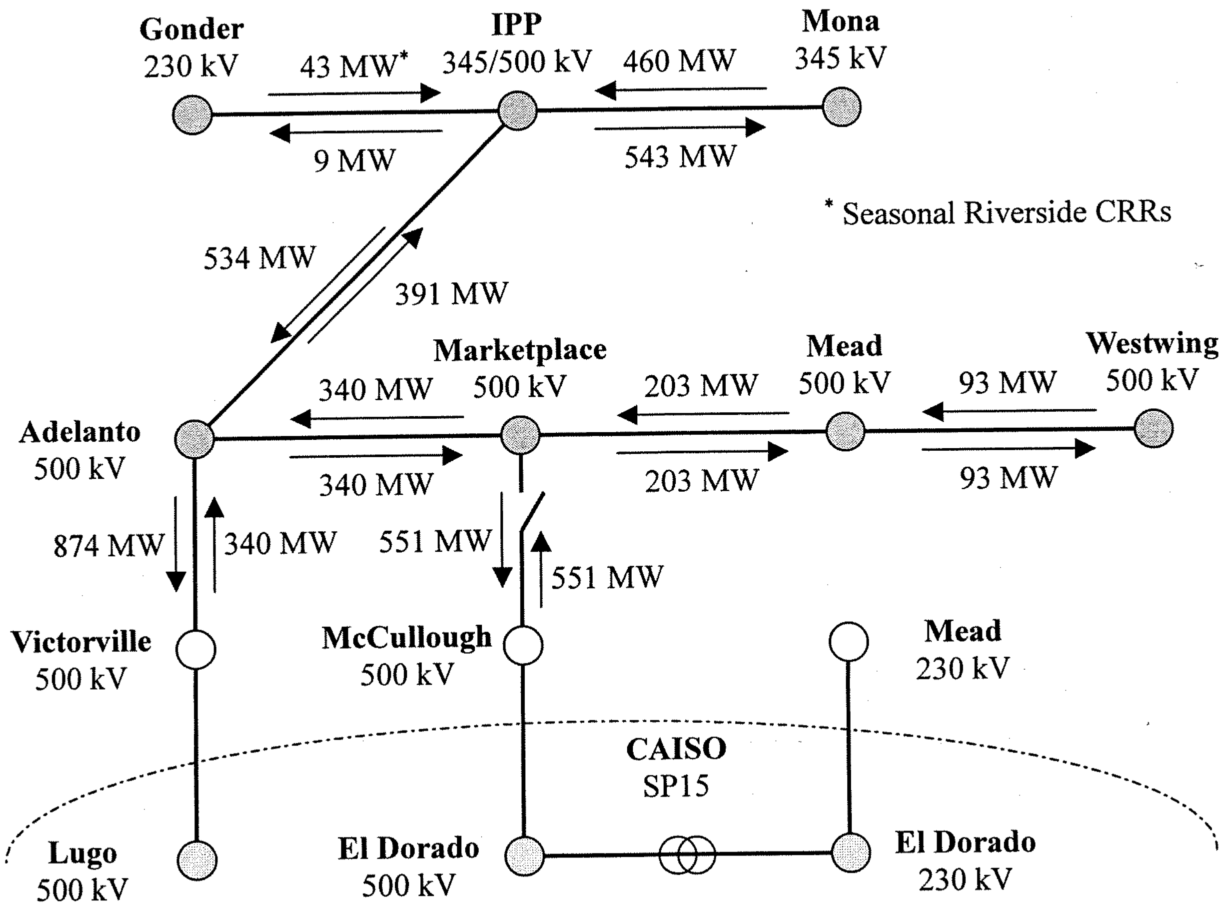
Gonder
230 kV
43 MW*
9 MW
IPP
345/500 kV
460 MW
543 MW
Mona
345 kV
* Seasonal Riverside CRRs
534 MW
391 MW
Marketplace
500 kV
Mead
500 kV
Westwing
500 kV
Adelanto
500 kV
340 MW
340 MW
203 MW
203 MW
93 MW
93 MW
874 MW
340 MW
551 MW
551 MW
Victorville
500 kV
McCullough
500 kV
Mead
230 kV
CAISO
SP15
Lugo
500 kV
El Dorado
500 kV
El Dorado
230 kV

Table 1 Monthly aggregate schedules on COI and Palo Verde by PG&E, SCE and SDG&E

	COI Branch Group (MWh)		Palo Verde Branch Group (MWh)	
Month (2003)	PGAE	SCE	SCE	SDGE
JAN	31,350	0	471,388	171,040
FEB	3,754	15,475	452,181	156,683
MAR	151,705	12,581	447,192	165,180
APR	137,064	225	364,821	149,850
MAY	158,876	9,739	439,482	171,466
JUN	162,834	28,200	612,043	179,335
JUL	215,303	10,700	846,935	186,104
AUG	254,493	4,729	755,507	180,354
SEP	221,804	1,125	779,713	174,459
OCT	263,036	4,755	506,215	187,319
NOV	169,310	0	686,227	175,405
DEC	154,948	0	822,722	192,303

Table 2 Utilization of COI and Palo Verde by PG&E, SCE and SDG&E

	COI Branch Group Utilization %		Palo Verde Branch Group Utilization %	
Month (2003)	PGAE	SCE	SCE	SDGE
JAN	1.8	0	55.2	23.7
FEB	0.2	1.0	58.7	24.0
MAR	8.9	0.7	52.4	22.8
APR	8.3	0.0	43.0	21.5
MAY	9.3	0.6	50.1	23.8
JUN	9.8	1.7	72.2	25.5
JUL	12.6	0.6	96.6	25.8
AUG	14.9	0.3	86.2	25.0
SEP	13.4	0.1	91.9	25.0
OCT	15.4	0.3	57.8	26.0
NOV	10.2	0	83.1	25.1
DEC	9.1	0	96.4	26.6

Table 3

Branch Group	Month (2003)	Total Scheduled (MWh)	Non Muni's Scheduled (MWh)	Muni Scheduled (MWh)	Utilization Factor for Muni's sched%	Utilization Factor for non Muni's sched %
LUGOIPPDC_BG	JAN	260,422	0	260,422	94.6	0.0
LUGOIPPDC_BG	FEB	177,116	0	177,116	71.2	0.0
LUGOIPPDC_BG	MAR	125,586	0	125,586	45.6	0.0
LUGOIPPDC_BG	APR	233,944	0	233,944	87.8	0.0
LUGOIPPDC_BG	MAY	259,468	0	259,468	94.3	0.0
LUGOIPPDC_BG	JUN	233,446	0	233,446	87.6	0.0
LUGOIPPDC_BG	JUL	261,524	0	261,524	95.0	0.0
LUGOIPPDC_BG	AUG	254,384	0	254,384	92.4	0.0
LUGOIPPDC_BG	SEP	243,217	0	243,217	91.3	0.0
LUGOIPPDC_BG	OCT	258,647	0	258,647	94.0	0.0
LUGOIPPDC_BG	NOV	229,152	0	229,152	86.0	0.0
LUGOIPPDC_BG	DEC	257,196	0	257,196	93.4	0.0
TOTAL		2,794,102	0	2,794,102	Average = 86.1	Average = 0.0
LUGOMKTPC_BG	JAN	2,550	2,550	0	0.0	1.4
LUGOMKTPC_BG	FEB	28,400	28,400	0	0.0	17.1
LUGOMKTPC_BG	MAR	24,359	13,879	10,480	5.7	7.6
LUGOMKTPC_BG	APR	12,650	12,490	160	0.1	7.0
LUGOMKTPC_BG	MAY	2,783	2,783	0	0.0	1.5
LUGOMKTPC_BG	JUN	5,590	5,590	0	0.0	3.1
LUGOMKTPC_BG	JUL	1,360	400	960	0.5	0.2
LUGOMKTPC_BG	AUG	456	0	456	0.2	0.0
LUGOMKTPC_BG	SEP	25,360	25,200	160	0.1	14.2
LUGOMKTPC_BG	OCT	19,408	19,276	132	0.1	10.5
LUGOMKTPC_BG	NOV	17,216	16,640	576	0.3	9.4
LUGOMKTPC_BG	DEC	20,890	20,890	0	0.0	11.4
TOTAL		161,022	148,098	12,924	Average = 0.6	Average = 6.9
LUGOTMONA_BG	JAN	91,688	23,314	68,375	57.4	19.6
LUGOTMONA_BG	FEB	89,664	26,720	62,944	58.5	24.9
LUGOTMONA_BG	MAR	79,344	12,136	67,208	56.5	10.2
LUGOTMONA_BG	APR	71,530	24,624	46,906	40.7	21.4
LUGOTMONA_BG	MAY	110,935	43,975	66,959	56.2	36.9
LUGOTMONA_BG	JUN	77,416	13,103	64,313	55.8	11.4
LUGOTMONA_BG	JUL	68,019	4,376	63,643	53.5	3.7
LUGOTMONA_BG	AUG	81,856	12,241	69,616	58.5	10.3
LUGOTMONA_BG	SEP	84,315	22,762	61,552	53.4	19.8
LUGOTMONA_BG	OCT	89,227	19,829	69,398	58.3	16.7
LUGOTMONA_BG	NOV	92,444	30,571	61,872	53.7	26.5
LUGOTMONA_BG	DEC	75,389	15,882	59,507	50.0	13.3
TOTAL		920,138	226,220	693,918	Average = 54.4	Average = 17.9
LUGOWSTWG_BG	JAN	32,728	4,160	28,568	41.3	6.0
LUGOWSTWG_BG	FEB	25,623	1,600	24,023	38.4	2.6
LUGOWSTWG_BG	MAR	29,827	1,480	28,347	41.0	2.1
LUGOWSTWG_BG	APR	23,883	450	23,433	35.0	0.7
LUGOWSTWG_BG	MAY	27,685	64	27,621	39.9	0.1
LUGOWSTWG_BG	JUN	18,761	0	18,761	28.0	0.0

LUGOWSTWG_BG	JUL	20,198	1,127	19,071	27.6	1.6
LUGOWSTWG_BG	AUG	22,192	2,704	19,488	28.2	3.9
LUGOWSTWG_BG	SEP	34,772	11,200	23,572	35.2	16.7
LUGOWSTWG_BG	OCT	23,188	1,104	22,084	31.9	1.6
LUGOWSTWG_BG	NOV	21,584	960	20,624	30.8	1.4
LUGOWSTWG_BG	DEC	28,958	5,318	23,640	34.2	7.7
TOTAL		309,400	30,167	279,232	Average = 34.3	Average = 3.7

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each person designated on the official service list compiled by the Secretary in these proceedings in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated at Folsom, CA on this 7th day of April, 2004.

Anthony Ivancovich