**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| California Independent System Operator Corporation | ) ) ) ) | Docket No. EL02-45 |

Pursuant to the Commission's Order of January 25, 2002, in the above-identified proceeding, the California Independent System Operator Corporation ("ISO") respectfully submits its Initial Brief. The ISO seeks reversal of the Arbitrator's Final Order and Award in *Pacific Gas and Electric Co.,* American Arbitration Association Case No. 71 198 00711 00 ("Award").

## SUMMARY

This proceeding concerns the ISO's ability to procure Ancillary Services necessary to comply with its obligation under the ISO Tariff to maintain the reliability of the ISO Controlled Grid and to fulfill its responsibilities as Control Area operator[1]. Section 2.5.1 of the ISO Tariff directs the ISO to procure sufficient Ancillary Services to maintain the reliability of the ISO Controlled Grid in compliance with reliability criteria of the Western Systems Coordinating Council ("WSCC") and the North American Electricity Reliability Council ("NERC") and to bill Scheduling Coordinators for those Ancillary Services. The Arbitrator

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

fundamentally misconstrued this section when he concluded that it authorizes the ISO to charge only for Ancillary Services procured to support transactions on the ISO Controlled Grid, and not for transactions in the ISO Control Area but not on the ISO Controlled Grid.

To the contrary, section 2.5.1 directs the ISO to ensure adequate Ancillary Services – and to recover the cost thereof – not simply *for* the ISO Controlled Grid, but *to maintain the reliability of* the ISO Controlled Grid. Thus, the ISO's authority to recover the cost of Ancillary Services is not determined by whether the transaction is on the ISO Controlled Grid, but rather by whether a lack of Ancillary Services for the transaction would endanger the reliability of the ISO Controlled Grid in violation of WSCC standards.

The ISO's authority to procure Ancillary Services must, therefore, extend to all transactions within the ISO Control Area on facilities that are directly or indirectly connected to the ISO Controlled Grid. If a Generator serving Load over such facilities fails, it will cause an imbalance between Generation and Load in the Control Area, which includes the ISO Controlled Grid. If the ISO lacks the Ancillary Services resources necessary to correct that imbalance, the reliability of the entire Control Area, including of the ISO Controlled Grid, will be put at risk. The amount of resources necessary is determined by WSCC criteria, and is based on *all* Load in the Control Area. Accordingly, in order to fulfill its responsibilities under section 2.5.1, the ISO must procure Ancillary Services for all transactions in the Control Area, regardless of whether they involve the ISO Controlled Grid.

Unlike the Arbitrator's misinterpretation of section 2.5.1, this reading gives meaning to the ISO Tariff as a whole, providing consistency with the various sections of the ISO Tariff regarding the ISO's procurement of Ancillary Services and its responsibilities as Control Area operator. It is also consistent with established standards for tariff interpretation.

In addition, those entities scheduling transactions with the ISO benefit from the ISO's coordination of their schedules with those on the ISO Controlled Grid. The ISO could not schedule those transactions, however, absent its maintenance of sufficient Ancillary Services. The Commission's policy that revenue responsibility should follow cost-causation thus compels the conclusion that those entities, as beneficiaries of the ISO's procurement of Ancillary Services, bear the costs of those Ancillary Services.

The particular transactions in this proceeding involve schedules on the California Oregon Transmission Project. By virtue of the fact that it has signed a Scheduling Coordinator Agreement and schedules these transactions with the ISO, Pacific Gas & Electric Company ("PG&E") is the responsible Scheduling Coordinator. Accordingly, under the ISO Tariff, PG&E is responsible for the cost of the Ancillary Services procured by the ISO in connection with schedules on the COTP.

## BACKGROUND

### I. Procedural Background

Following a protracted period of Good Faith Negotiations, PG&E filed a Statement of Claim against the ISO under section 13.2.2 of the Tariff in October

2000. The Statement of Claim concerned charges for Ancillary Services that the ISO procured in connection with transactions scheduled by PG&E on the COTP.[2] Subsequently, statements of Claim and Petitions to Intervene raising the same issues as had been raised by PG&E were filed by Modesto Irrigation District; Cities of Redding and Santa Clara, M-S-R Public Power Agency and the Transmission Agency of Northern California ("TANC"); SMUD; and Turlock Irrigation District. The Northern California Power Agency filed a Petition to Intervene but not a Statement of Claim. On November 22, 2000, the ISO filed a Response to Claim and Counterclaim.

In its Statement of Claim, PG&E sought reimbursement from the ISO for the amounts it claims it paid to the ISO by mistake during the period between April 1998 and April 1999. In its Response to Claim and Counterclaim, the ISO denied that PG&E was entitled to reimbursement of the Ancillary Service costs PG&E had paid to the ISO during that period, and sought recovery from PG&E for Ancillary Service costs incurred by the ISO since May 1, 1999, plus interest. In addition, the ISO sought a declaration that PG&E is required to continue to pay for costs incurred by the ISO to support COTP Schedules and to continue to act as the COTP Scheduling Coordinator.

On August 2, 2001, PG&E and the Intervenors filed a Motion for Summary Judgment seeking summary disposition of their claim(s) and of the ISO's

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[2] In addition to the COTP, this proceeding concerns certain transmission facilities owned by the Sacramento Area Municipal Utility District ("SMUD") and the Western Area Power Administration, known as the Bubble. The charges involved, however, only involve those Bubble transactions that also involve the COTP. (Tr. 31:1-3 (R. 02080)) Accordingly, the ISO will refer to the COTP and the Bubble together as the COTP in this brief.

counterclaim based on their contention that the ISO lacks the authority under its Tariff to assess Ancillary Services costs attributable to transactions off the ISO Controlled Grid. In addition, PG&E denied that it ever agreed to pay any charges related to COTP schedules. The ISO's Opposition to the Motion contended that both disputed factual and legal issues precluded granting of the Motion. After a full hearing on September 5, 2001, the Arbitrator denied the motion on September 14, 2001, ruling that the Tariff standard applicable to such motions had not been satisfied. However, the Arbitrator also ruled that the evidentiary hearing would be phased, pursuant to Rule 32(b) of the American Arbitration Association Rules. In the first phase, evidence would be heard on the decisional significance of the ISO's statements accompanying its filing at FERC of Amendment No. 2 (FERC Docket Nos. EC96-19-015 and ER96-1663-016) and of FERC's ruling on that filing, apparently in light of those statements, *California Ind. Sys. Oper. Corp.,* 82 FERC ¶ 61,213 (1998). The denial of the Motion was without prejudice to its renewal at the end of this first phase of the hearing. If not renewed or if made and denied, the second hearing phase would cover the remainder of the parties' presentations.

Pursuant to the pre-hearing order and section 13.3.6 of the ISO Tariff, PG&E and the Intervenors brought an oral Motion for Summary Disposition at the conclusion of the first phase of the arbitration hearing that commenced on October 1, 2001. The Arbitrator denied that motion on October 2, 2001. Thereafter, the arbitration hearing continued to the second hearing phase for five days of additional testimony and evidence, and concluded on October 10, 2001. Following the hearing, the parties filed initial and reply briefs.

On December 13, 2001, the Arbitrator issued his Final Order and Award, which granted PG&E's claim and denied the ISO's counterclaim. On January 4, 2002, pursuant to section 13.4 of the ISO Tariff, the ISO filed a petition requesting review of the Arbitrator's order.

## II. Factual Background

### A. The COTP

The COTP is a 500 kV transmission project extending from the California-Oregon border and the Bonneville Power Administration to an interconnection in central California with the Pacific AC Intertie near PG&E's Tesla Substation. (ISO-2, (R. 04463, 04536-04537).). The COTP, authorized by Congress in 1985, was designed to increase the transfer capability between California and the Pacific Northwest. The TANC constructed the COTP for members and for other participants (the members of TANC and the other participants are herein referred to as the "COTP Participants"). It was completed in 1993. Though investor owned utilities ("IOUs") had hoped to own part of COTP (and participated in its planning and design), the California Public Utility Commission ("CPUC") denied their applications for certificates of public convenience and necessity. As a result, the CPUC directed the IOUs to withdraw from the COTP project. (ISO Exh. 3 (R. 04547-48))

The COTP is part of the California Oregon Interconnection, and runs in parallel with the Pacific AC Intertie, which is owned by the IOUs. (*Id.* (R. 04548).) In order to ensure the reliability and transfer capacity of the COTP, it must be scheduled in coordination with the Pacific AC Intertie. (ISO Exh. 2, COA §§ 1; 2.5.2 (R. 04459-60); Tr. 908:20- 909:1, (R. 02958-59).)

### B. The Coordinated Operations Agreement

Prior to commencement of ISO operations in March 1998, PG&E was the Control Area Operator for northern California and for the COTP. The COTP Participants and the IOUs executed the Coordinated Operations Agreement ("COA") to cover the coordinated operation of the COTP and the Pacific AC Intertie. Under the COA, PG&E had the obligation to schedule COTP transactions. (ISO Exh. 2 COA § 8.4 (R. 04484-92).) At its broadest level, the COA required PG&E to take schedules from the COTP Participants to use in its total Control Area operations. More specifically, as the Commission has noted:

> The COA sets forth procedures for: (1) determining the transfer capability of the COTP and the Pacific AC Intertie as a single system; (2) allocating transfer capability between the COTP and the Pacific AC Intertie; (3) allocating available scheduling capability and sharing curtailments between the COTP and the Pacific AC Intertie; (4) scheduling of power at the California-Oregon border; (5) assessing the impact of connections and modifications; (6) providing for the coordination of the COTP and the Pacific AC Intertie in a reliable manner; (7) determining losses; and (8) coordinating administrative and technical matters and resolving disputes.

*Pacific Gas & Electric Co.*, 93 FERC ¶ 61,322 at 62,102(2000).The COA also establishes that the COTP is within PG&E's Control Area, and that PG&E will integrate the COTP into its Control Area Responsibilities. (ISO Exh. 2, COA § 8.2.1 (R. 04476-77).)

### C. Formation of the ISO and Assumption of PG&E Control Area Responsibilities

In a series of orders in 1996 and 1997, the Commission approved the formation of the ISO and the transfer to the ISO of transmission facilities owned by three IOUs, including PG&E. See e.g., *Pacific Gas and Electric Company, et al.,* 77 FERC ¶ 61,204 (1996), *Pacific Gas and Electric Company, et al.,* 81 FERC ¶ 61,122 (1997). The ISO commenced operations on March 31, 1998 (Tr. 909:2-19, (R. 02959).) Those facilities owned or controlled (through contractual entitlements) by the IOUs that were turned over to the ISO's Operational Control constitutes the ISO Controlled Grid. ISO Tariff, Appendix A, Original Sheet No. 327 (*see also,* Tr. 26:25- 27:9, (R. 02075-76).)[3] As a result, the Pacific AC Intertie is part of the ISO Controlled Grid. The COTP is not.

Along with Operational Control of the IOU's transmission facilities, the ISO assumed the role of Control Area operator, including what had been PG&E's Control Area operator responsibilities. (Tr. 42:16 - 43:1, 909:16-19 (R. 02091-92, 02959)) As Control Area operator, the ISO must maintain the Control Area in accordance with criteria established by the WSCC and the National Electricity Reliability Council. Award at 20. (*See also* ISO Exh. 8, (R. 04644), ISO Exh. 22, (R. 05563).) The WSCC criteria with which the ISO must comply include the Minimum Operating Reliability Criteria ("MORC"). Award at 20. (*See also* ISO Exh. 8, (R. 04666).) The MORC require, among other things, that the ISO ensure adequate Regulation and Operating Reserves for the Control Area. (*Id.*

[3] Subsequently, the City of Vernon transferred Operational Control of its transmission facilities to the ISO. (Tr. 27:10-11, (R. 02076).)

at 2 (R. 04669); Tr. 269:8-21, (R. 02318).) Both Regulation and Operating Reserves are required for reliable service of load and the amount required is not contingent upon the delivery path, or transmission line, that is used to transmit Energy from its Generation source to the load. (Exh. ISO-8 at 2 (R. 04619).)

### D. Pre-operations Discussions

Prior to the commencement of the ISO's operations, representatives of the ISO met with management from both PG&E and the COTP Participants to discuss the operation and scheduling of COTP transactions. These meetings, both in person and on the phone, spanned more than six months, with the bulk of the meetings occurring between January and the end of March 1998. Indeed, there were dozens of such meetings to discuss both issues associated with ISO start-up and with the responsibility of the parties thereafter. (Tr. 39:7-11; 226:11-22 (R. 02088; R. 02275).)

The ISO presented evidence during the Arbitration, including notes of a March 24 meeting with PG&E, that PG&E agreed at that meeting that it would continue to Schedule COTP transactions and pay the ISO for any Ancillary Services in connection with COTP transactions, which the ISO had to procure when those services were not self-provided. (Exh. ISO-9 (R. 04712); Tr. at 233:19 - 235:14; 237:17 - 241:4; 812:19 - 813:16 (R. 02282--84; 02286-90; 02860-61).) Mr. Fluckiger noted that he asked, "What happens if you lean on the grid, what happens if you don't self-provide… And the repeated assurance [of PG&E and the COTP Participants] was, We'll self-provide that. And I would then ask, And if you don't? Fine, we're responsible for if we lean on the grid…." (Tr. 240:15-23, (R. 02289).) The ISO's evidence showed that PG&E's agreement that it would continue to schedule the COTP and Bubble transactions was fully known to all the parties precisely because it had been the product of weeks of negotiations before the ISO started its operations. (Tr. 241:8-20, (R. 02290).).

In furtherance of PG&E's agreement to continue its role in scheduling COTP transactions, a separate Scheduling Coordinator ID was established for PG&E, the COTP Scheduling Coordinator ID. (ISO Exh. 20 (R. 04893); Tr. 272:24- 273:6, (R. 02321-22).) The ISO's evidence showed that this ID was created to ensure that the PG&E-ISO agreement could be implemented by segregating PG&E's COTP loads from its non-COTP loads so that its COTP loads would not be assessed five exempted ISO charges. (Tr. 236:4-238:4; 1131:16-1133:13; 1186:8-1187:9 (R. 02285-87; R. 03181-83; R. 03236-37).) The ISO testified that it never made any agreement with PG&E or the COTP Participants that would have waived or exempted them from the payment of the Ancillary Service costs that the ISO incurred in connection with schedules submitted by PG&E on behalf of COTP. (Tr. 240:11-23, (R. 02289).) As PG&E's own witness states:

> Q. There's no writing that exists, so far as you are aware, that says that PG&E will be incurring no Ancillary Service charges in connection with the scheduling of the COTP and bubble transactions; isn't that right?
>
> Eshbach: The only document I am aware of is a draft set of operating procedures for the COTP that is an ISO document, not a PG&E document.
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> Q. No executed writing?
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> Eshbach: That's right, no executed, in writing.

> Q. So far as you know, the only executed writing that specifies what charges will not be assessed on these off-grid transactions is the GMC Settlement; isn't that correct?
>
> Eshbach: I think that is correct, yes. (Tr. 508:2-16, (R. 02557).)

PG&E asserts that it understood that the COTP Proxy ID meant that PG&E would incur no charges whatsoever while accommodating the ISO's desire to receive the COTP and Bubble schedule information in a manner compatible with the ISO's computer systems. (PG&E Reply Brief at 4). PG&E, however, presented no witness that was present at the meeting of March 24, 1998.

### E. Post Operations Practices

Following commencement of ISO operations, PG&E began scheduling COTP transactions using the COTP Scheduling ID. The ISO issued PG&E daily Preliminary and Final Settlement Statements and monthly invoices reflecting the charges for Ancillary Services in connection with the COTP. (Exh. ISO-20, (R. 04893); Tr. 521:3-12(R. 02570); Tr. 1135:1-18 (R. 03185); ISO Exh. 7 (R. 04583); ISO Exh. 18 (R. 04845).) Those were assigned to the COTP Scheduling ID in the Preliminary Settlement Statements and transferred to PG&E's Scheduling Coordinator ID for Existing Contracts (PGAE) upon issuance of the Final Settlement Statements. (Tr. 527:2-12 (R. 02576); Tr. 1140:25-1141:11 (R. 03190-03191); Exh. ISO-7 (R. 04583); & Exh. ISO-18 (R. 04845).) Between April 1998 and April 1999, the ISO charged PG&E $14,172,337 for Ancillary Services procured in connection with COTP transactions. (Tr. 458:8-10 (R. 02507); Tr. 481:15-19 (R. 02530)) PG&E paid those invoices. Decision at 2.

On behalf of the ISO, Mr. Hoffman testified that he discussed with Mr. Cowden, the PG&E employee initially responsible for reviewing and authorizing payment of those bills, that the ISO was "charging the COTP ID for AGC regulation and replacement reserves, and on occasion, for inadequate self-provision of spin and nonspin." (Tr. 1152:2-5, R. 03202.) PG&E witnesses testified that they received and reviewed ISO's COTP and PGAE Preliminary and Final Settlement Statements during the first year of ISO operations that plainly reflected those charges accruing. (Tr. 1494:2-7; R. 03544, ISO Exh. 7 (R. 04583); & ISO Exh. 18 (R. 04845).) Mr. Hoffman also testified that Mr. Crowden of PG&E questioned the Preliminary Settlement Statement regarding Ancillary Service charges prior to April 1999. Mr. Crowden acknowledged that the ISO was charging the PG&E COTP ID for certain Ancillary Services. (Tr. 1151:7-1152:7, R. 03201-03202.)

PG&E, however, asserts that it only cursorily reviewed the Preliminary Statements, and did not have reason to examine the PGAE Final Settlement Statement for COTP-related charges. Accordingly, it states, it was unaware of the charges for COTP-related Ancillary Services were rolled into either the PGAE Preliminary or Final Settlement Statements. (Tr. at 456:18-457:1; 1479:9-1480:7, (R. 02505-02506, , 03529-30).)

Once PG&E challenged the COTP related Ancillary Service charges, and threatened to stop scheduling the COTP transactions, the ISO temporarily agreed, without waiving or prejudicing any of its rights to recover payment, not to bill PG&E for additional COTP Ancillary Services pending resolution of this current dispute[4]. (Tr. 483:2-12, R. 02532; ISO Exh. 16 ¶ 13 (R. 04842).) The

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[4] If the ISO did not receive the COTP schedules, it would not know of potentially significant amounts of Energy coming into the ISO Control Area; would not be able to fulfill its

ISO has continued to keep track of the additional funds that PG&E owes it for continued provision of Ancillary Services for COTP. By the time of the Arbitration, an additional $38,510,291 had accrued. This was the subject of the ISO's Counterclaim.

## III. Arbitration Decision

The Arbitrator issued his Award on December 13, 2001. The Award granted PG&E's claim (with the claims of the other parties subsumed in this Award) and denied the ISO's counterclaim in its entirety. Specifically, the Arbitrator concluded that Tariff provisions defining the ISO's authority to charge for Ancillary Services did not extend that authority to the Control Area, but confined it to the ISO Controlled Grid, which does not include the COTP facilities. The Arbitrator stated that this conclusion was reinforced by the history of Amendment No. 2 to the Tariff, filed on February 25, 1998.

The Arbitrator also concluded that PG&E had not, in pre-startup discussions, agreed to assume the obligations of a Tariff-defined Scheduling Coordinator for the COTP schedules. The Arbitrator concluded that there was no meeting of the minds between the ISO and PG&E with regard to the charges for Ancillary Services in connection with COTP schedules. He relied upon PG&E's denials of an agreement, and found the ISO's contemporaneous documentary evidence nondispositive. Award at 14-15.

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responsibilities of a Control Area operator by being able to checkout transactions with neighboring Control Areas (Exh. ISO-8 (R. 04644)); and would be violating the WSCC Control Area operator requirements. *Id.*

The Arbitrator concluded that, absent Tariff authority to charge PG&E for COTP- related Ancillary Services, Commission precedent did not provide an alternative basis for the ISO to recover those costs from PG&E. The Arbitrator also concluded that PG&E's claim was contestable and not time barred because PG&E was not aware of, and was not deficient in failing to learn of, the disputed charges before April 1999. Finally, the Arbitrator concluded that, as a matter of fairness and equity, PG&E should not be made to bear the costs of the ISO's exercise of its discretion as Control Area operator (with which he did not take issue) regarding the Ancillary Services required to satisfy the applicable reliability standards (although he did conclude that it would not be unreasonable to require all the participants in the market to bear those costs).

## STANDARD OF REVIEW

To the ISO's knowledge, this is the first time that Commission has been asked to review an arbitration award. The standard of review is thus a matter of first impression. In its Policy Statement Regarding Regional Transmission Groups; Policy Statement, 58 FR 41626 (August 5, 1993), the Commission stated generally with regard to its review of ADR decisions:

> We will not attempt to decide in this Policy Statement exactly what degree of deference we will be willing to afford. This may depend on a number of factors including, but not limited to, the type of issue to be resolved, the degree of specificity in the RTG agreement, the ability of any party to exercise market power, and type of ADR being used. We will make that decision based on the particular facts of the proposals presented to us.
>
> For example, it may be appropriate to give considerable deference to an arbitrator's finding on a purely factual issue, such as how much an improvement to the system will cost. This is somewhat analogous to factual decisions of administrative law judges, to which we afford considerable deference. However, just as we would not defer to an

> administrative law judge's decision that is directly contrary to Commission policy, we would not defer to an arbitrator's decision that is directly contrary to Commission policy. Other factors that might influence the degree of deference we would afford to the outcome of a dispute resolution process include, for example, whether a party can or does object to the decision, the degree to which the decision was reached under procedures that maximize fairness, and the degree to which the decision is based on a well-developed record.

*Id.* at 41631.

Section 13.4.2 of the ISO Tariff states that the parties intend that the Commission should afford substantial deference to factual findings of the Arbitrator. By implication, legal conclusions, such as the interpretation of the ISO Tariff, are not to receive this same deference. The ISO submits that the determination of tariff requirements, and ensuring that such requirements are interpreted in a manner that is just and reasonable in light of The Commission's policies, lies at the core of the Commission's responsibilities under Section 205 of the Federal Power Act. It draws upon the Commission's technical expertise and is essential to discharging the Commission's obligation to ensure that its policies are appropriately implemented. Accordingly, the Commission should review the Arbitrator's interpretation of the ISO Tariff (and any related documents) de novo.

## ARGUMENT

### I. The ISO Tariff provides Authority to the ISO to Charge for Ancillary Services Procured in Support of Transactions Within the ISO Control Area but Not on the ISO Controlled Grid

#### A. The ISO Tariff Unambiguously Provides Authority to the ISO to Charge for Ancillary Services Procured in Support of Transactions Within the ISO Control Area, but Not on the ISO Controlled Grid, Because Those Ancillary Services Are Necessary to Maintain the Reliability of the ISO Controlled Grid

The fundamental flaw of the Arbitrator's decision lies in his analysis of section 2.5.1 of the ISO Tariff. He states, "Tariff § 2.5.1, which is central to the ISO's analysis, authorizes the ISO to ensure the adequacy of Ancillary Services for the ISO Controlled Grid, not the Control Area." Award at 7. It is this incorrect reading of section 2.5.1 that is the lynchpin of the Arbitrator's analysis. By its plain terms, section 2.5.1 directs the ISO to ensure adequate Ancillary Services not simply *for* the ISO Controlled Grid, but *to maintain the reliability of* the ISO Controlled Grid, and authorizes recovery of the associated costs from Scheduling Coordinators. The Tariff provision could have limited the ISO's Ancillary Services responsibility just to transactions conducted *over* the ISO Controlled Grid. Such a limitation would have lent support to the Arbitrator's reading. But the Tariff does not do so, and for a very good reason – such a limitation would have defeated the very purpose of section 2.5.1. The reliability of the ISO Controlled Grid cannot be maintained if the ISO is indifferent to activities that *affect* that grid even though they are not using it. The definitive inquiry, therefore, is not whether the Ancillary Services are in connection with a transaction on the ISO Controlled

Grid, but rather whether the lack of those Ancillary Services would affect the reliability of the ISO Controlled Grid in violation of WSCC and MORC standards.

When this plain meaning is applied to the ISO's purchases of Ancillary Services for the COTP, the ISO's authority is clear. If a Generator serving Load over the COTP fails, it will cause an imbalance between Generation and Load in the Control Area, which includes both the Load served directly by the ISO Controlled Grid and the remaining load not in the Distribution System of a TO or UDC. (Tr. 223:7-224:10 (R. 02272-02273); Tr. 1093:3-1094:20 (R. 03143-03142); Tr. 1156:20-1157:3 (R. 03206-03207).) If that imbalance, which shows up in the ISO's monitoring systems, is not corrected, the reliability of the entire Control Area, including of the ISO Controlled Grid, will be put at risk. (*Id.*, Exh. ISO-8, MORC at 1-4 (R. 04668-04671).)The ISO corrects the imbalance by using Ancillary Services: first, units with Automatic Generation Control that are providing Regulation will respond with Energy to replace the lost Generation; subsequently, the ISO will dispatch Energy from Operating Reserves or Supplemental Energy bids to bring those units back to their preferred operating points. ISO Tariff § 2.5.22.2. This necessarily requires that the ISO have adequate Ancillary Services for the COTP-served Load.

More specifically, the WSCC MORC require the ISO to maintain adequate Ancillary Services (e.g., contingency reserves for 7 percent of Load served by thermal Generation and 5 percent of Load served by other Generation) for its "load responsibility." (Exh. ISO-8 (R. 04669); Tariff § 2.5.2.1; Tariff § 2.5.2.3). The ISO's load responsibility includes the "*control area's* firm load demand."

(Exh. ISO-8 (R. 04669) (emphasis added).) There is no dispute that this includes Demand from Load served over the COTP. If there is a contingency anywhere in the Control Area that affects the ISO's Control Area Error, and if the ISO has not ensured sufficient Ancillary Services to maintain the reliability of the Control Area consistent with WSCC criteria (i.e., for all Load, including COTP Load), *a fortiori* the ISO has not ensured "sufficient Ancillary Services . . . to maintain the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria," as required by section 2.5.1. Hence, to read section 2.5.1 as limiting the ISO's authority to procure Ancillary Services for Loads that, if not supported, could affect the reliability of the ISO Controlled Grid (i.e., transactions over the COTP), is to misread the fundamental objective of that critical Tariff section. To read that section as limiting the ISO's authority to charge the Scheduling Coordinator for those Loads that necessitate the procurement of such Ancillary Services is to render that procurement authority essentially ineffectual.

### B. In Order to Give Meaning to the Whole of the ISO Tariff, It Must Be Interpreted to Provide the ISO with Authority to Charge for Ancillary Services Procured in Support of Transactions Within the ISO Control Area, but Not on the ISO Controlled Grid

Even if the above reading of section 2.5.1 were not compelled by its plain language, it would be required under ordinary rules of construction applicable to jurisdictional tariffs. Although the Arbitrator quite correctly evaluated the ISO's authority by looking "within the four corners of the [ISO] Tariff" (Award at 7), *see, e.g., Consolidated Gas Transmission Corp. v. FERC*, 771 F.2d 1526 (D.C. Cir. 1985), he failed to interpret the Tariff as a whole and to give meaning, whenever possible, to all of its provisions. *Columbia Gas Transmission Corp.*, 27 FERC ¶

61,089 (1984). Instead, the Arbitrator simply focused on the Tariff references to the "ISO Controlled Grid" to the exclusion of the explicit Tariff requirement that the ISO operate in compliance with WSCC and NERC reliability criteria. As the Commission has made clear in a somewhat analogous setting, this type of tunnel-vision approach to tariff interpretation is highly inappropriate. *See Northeast Associates v. Boston Edison*, 91 FERC ¶ 61,069 (2000).[5]

When the ISO's Tariff is considered as a whole, it can only be read to authorize and require the ISO to procure Ancillary Services for transactions within the Control Area (but not on the ISO Controlled Grid) – and to recover the costs of such Ancillary Services from the Scheduling Coordinators whose schedules necessitate the procurement – if such transactions have the potential to affect the reliability of the ISO Controlled Grid.

The ISO Tariff expressly requires the ISO to "establish a WSCC approved Control Area and control center" and to operate the ISO Controlled Grid in accordance with WSCC and NERC reliability criteria. (Tariff § 2.3.1.1). Because

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[5] In that proceeding, the complainant sought a Commission order prohibiting the respondent from disconnecting complainant's plant to accommodate the interconnection of another plant. Complainant cited language in section 5.1 of the interconnection agreement that required continuous interconnection "insofar as this can be done without imminent, significant disruption of service . . . and without imminent danger to life or property." The section also specified that the interconnection would be operated in compliance with NEPOOL requirements. The Commission, despite a dissent arguing that the language was unambiguous, denied the complaint. It concluded:

> We disagree with [complainant's] interpretation because it would prohibit any service interruption except in cases of imminent service disruption and imminent danger to life or property. By focusing only on the first sentence section 5.1, [complainant] fails to give effect to the remaining language in section 5.1 that recognizes [respondent's] obligation to operate in compliance with the rules and requirements of NEPOOL. [Complainant's] interpretation is also inconsistent with our reading of other provisions of the interconnection agreement.

91 FERC at 61,253.

the ISO must be the operator of a WSCC approved Control Area, and because WSCC and NERC reliability criteria apply on a Control Area basis (Tariff § 2.5.2.2; Tr. 51:22-52:1; R. 02100, ISO Exh. 8 at 2 (R. 04669); ISO Exh. 22 at 1 (R. 05568)), the ISO's responsibilities and authority necessarily must reach beyond the ISO Controlled Grid to the ISO Control Area.

As discussed above, under the MORC, Ancillary Services requirements are calculated as a function of Control Area load. (ISO Exh. 8 at 2, (R. 04669); Tr. 120:2-11, (R. 02169).) Thus, where Energy is scheduled into or out of the ISO Control Area, and there is no evident, effectively confirmed, and verified corresponding self-provided Ancillary Services on a per unit basis, the ISO *must* procure additional Ancillary Services to ensure Control Area reliability. (Tr. 267:13-18 (R. 02316).) If the ISO fails to do so, it is not fulfilling its responsibility as Control Area operator and, hence, not operating the ISO Controlled Grid, which is within the Control Area, in accordance with WSCC reliability requirements. As Control Area operator, the ISO cannot isolate the reliability of the ISO Controlled Grid from that of the ISO Control Area.

Indeed, before the Arbitrator, PG&E did not even take issue with the ISO's obligation and authority to acquire Ancillary Services in these circumstances, but only its authority to recover the associated costs from the Scheduling Coordinator whose schedule imposed the requirement:

> The ISO also oversees a region known as the ISO Control Area. Both the ISO Controlled Grid facilities and the Off Grid facilities are within the geographic boundaries of the ISO Control Area and, as mandated by the ISO Tariff, the ISO must operate that area in accord with NERC/WSCC guidelines. However, while the ISO Tariff grants the ISO authority over the ISO Controlled Grid, the ISO Tariff does *not* grant the ISO any such

> authority over Off Grid facilities. Rather, the ISO Tariff merely indicates that the ISO will operate the ISO Control Area pursuant to NERC/WSCC *guidelines*. The fact that the ISO must comply with NERC/WSCC guidelines does *not* provide the ISO with any authority to assess charges on PG&E for Off Grid transactions. Authority to assess charges can only come from the ISO Tariff.

PG&E Br. at Post-Hearing Br. at 2-3.

The issue is not, however, control over "off-grid" facilities. The issue, instead, is the financial responsibility for Ancillary Services that are necessitated when a party chooses to schedule transactions over "off-grid" facilities that directly affect the reliability of the Control Area, *including* the ISO Controlled Grid, and thus the ISO's ability to fulfill its Tariff responsibilities.

The Arbitrator nonetheless agreed with PG&E's argument, finding that the ISO's ability to charge for Ancillary Services is limited by the references in various sections of the ISO Tariff to operation of the "ISO Controlled Grid." Award at 8. PG&E and the Arbitrator incorrectly interpret the Tariff.

As discussed above, section 2.5.1 of the Tariff authorizes the ISO to charge for Ancillary Services that it deems necessary to procure for the maintenance of reliability: "The ISO will calculate payments for Ancillary Services to Scheduling Coordinators and charge the cost to Scheduling Coordinators." Section 11.2.3 similarly provides that: "The ISO shall calculate, account for, and settle charges and payments for Ancillary Services as set out in sections 2.5.27.1 to 4, and 2.5.28.1 of this ISO Tariff." On their face, both provisions expressly authorize the ISO to charge Scheduling Coordinators for Ancillary Services — without regard to the location of these services — that the ISO procures on their behalf. (When a transaction within the Control Area cannot be accommodated without affecting adversely reliability absent the acquisition of Ancillary Services, the acquisition unambiguously is occasioned by and benefits directly that transaction.) Importantly, neither section 2.5.27.1 nor section 2.5.28.1 limits the ISO's authority to charge for Ancillary Services to those procured in support of transactions conducted on the ISO Controlled Grid.

Moreover, although the definition of Ancillary Services in Appendix A refers to the "ISO Controlled Grid," it does not do so in any restrictive sense. To the contrary, consistent with section 2.5.1, the definition embraces those "services [deemed by the ISO as necessary] to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice." The phrase "while maintaining reliable operation of the ISO Controlled Grid" cannot logically be read as limited to the support of transactions within "the ISO Controlled Grid" where transactions scheduled elsewhere in the Control Area have critical reliability implications for the ISO Controlled Grid. The definition of Ancillary Services, like section 2.5.1, instead takes the more expansive view of the ISO's responsibilities that alone is consistent with meeting the fundamental reliability objective that, after all, is the entire reason for the Ancillary Service requirement in the first place.

Other Tariff provisions support this reading. For example, the ISO has the sole authority *and discretion* to determine the quantity, quality and location of Ancillary Services and to verify their self-provision, where appropriate, in carrying out its Control Area reliability responsibilities.[6] The only restriction on the ISO's exercise of such authority and discretion is stated as a minimum: the ISO must at least satisfy the requirements established by WSCC MORC and NERC.[7] Moreover, section 2.5.2.2 – which requires review of the ISO Controlled Grid operation to determine any revision to the Ancillary Services standards *to be used in the Control Area* – only makes sense if the ISO must maintain sufficient Ancillary Services to meet the WSCC MORC criteria for the Control Area.

The Arbitrator's focus in reviewing these provisions – on the reference to the operation of the ISO Controlled Grid – was too narrow. It fails to reconcile the ISO's responsibilities with its ability to recover its costs. It recognizes that the ISO must operate the ISO Controlled Grid in a manner consistent with reliability criteria, but it denies the ISO the tools necessary to fulfill that responsibility. This is not a rational interpretation and it must be rejected.

### C. The ISO's Authority to Charge for Ancillary Services Procured for Transactions Within the ISO Control Area but Not on the ISO Controlled Grid Is Supported By the Commission's Standards for Tariff Interpretation

Certain principles guide tariff interpretation in the case of ambiguity. Although, as discussed above, the ISO's authority to charge for Ancillary Services procured for transactions within the ISO Control Area but not on the ISO

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6 Section 2.5.2.1 requires that the standards developed by the ISO "shall be used as a basis for determining the quantity and type of each Ancillary Service which the ISO requires to be available." Further, for each type of Ancillary Service, the "ISO shall determine the quantity and location of the Ancillary Service which is required and which must be under the direct Dispatch control of the ISO on an hourly basis each day." (Tariff § 2.5.3.)

7 "The ISO may establish planning and Operating Reserve criteria more stringent than those established by the WSCC and NERC or revise the Local Reliability Criteria subject to and in accordance with the provisions of the [Transmission Control Agreement]." (Tariff § 2.3.1.3.2.)

Controlled Grid is not ambiguous, it is instructive that those principles support the ISO's authority.

Among those principles is that "[a] tariff is no different from any contract . . . [a]nd, thus, its true application must sometimes be determined by the factual situation upon which it is sought to be impressed." *Penn Central Co. v. General Mills, Inc.*, 439 F.2d 1338, 1340 (8th Cir. 1971). Further, the tariff must have a reasonable construction that does not yield unfair, unusual, absurd, or improbable results. *Id.* It also should not be strictly construed against the provider if there is a reasonable construction that conforms to the intention of the drafters, avoids violations of law, and accords with the practical application given by providers and customers. *Id; see also AEP Generating Co.*, 39 FERC ¶ 61,158, at 61,626 (1987) (construction of the tariff must accord with "the meaning of the words intended" and avoid "unfair, unusual absurd or improbable results"). The Commission rejects any construction that would be "both contrary to principles of mutuality and incongruous." *AEP Generating Co.* at 61,626.[8]

Certain unassailable facts loom large in the "factual situation" to which the Commission must refer. Foremost is that, under orders of the Commission, the ISO is the Control Area operator. *Pacific Gas & Electric Co.*, 81 FERC ¶ 61,122 at 61,456 (1997). As the Control Area operator, the ISO must comply with the

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[8] In *AEP Generating Co.*, a utility contended that the Commission could not require it to enter a purchase power agreement because it was entitled, under the filed rate, to rely upon the capacity equalization mechanism in an interconnection agreement. The Commission, however, applied its technical expertise in power pooling and integrated system arrangements to construe the interconnection agreement in accordance with "the meaning of the words intended" and to avoid "unfair, unusual absurd or improbable results." 39 FERC at 61,626. It found that the capacity equalization mechanism was purely a financial device, stating that allowing a utility to rely upon it would be "both contrary to principles of mutuality and incongruous."

WSCC MORC. *Id.*; Award at 20; *see also* ISO Tariff § 2.3.1.3.1. The WSCC MORC require the ISO to maintain Regulation and Operating Reserves based on the entire firm Load in the ISO Control Area, not just that Load located on the ISO Controlled Grid. (Exh. ISO-8 at 2 (R. 04669).). To the extent that Ancillary Services are not self-provided, the ISO must procure them. Tariff § 2.5.1. This responsibility is consistent with the Control Area operator's role as Ancillary Services provider of last resort under Order No. 888.[9] Indeed, the Commission's orders in connection with the ISO Tariff, as initially filed, treated the operation of the ISO Controlled Grid as an inseparable adjunct to the ISO's Control Area responsibilities. For example, the Commission insisted that the ISO have the discretion to determine, based on its *Control Area* responsibilities, which facilities of the Participating Transmission Owners would be included in the ISO Controlled Grid. *Pacific Gas & Electric Co.*, 77 FERC ¶ 61,204 at 61,822 (1996). *See also*, *Pacific Gas and Elec. Co.*, 81 FERC ¶ 61,122 at 61,456-57, 61,496, and 61,499 (1997). In light of these facts, an interpretation of the ISO Tariff that denied the ISO the right to charge the Scheduling Coordinator on whose behalf it must procure Ancillary Services would indeed be "unfair, unusual, absurd, or improbable," as well as "contrary to principles of mutuality and incongruous."

[9] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 *Fed. Reg.* 21,540 (1996), *FERC Stats. and Regs,* ¶31,036 at **31,716**, and n. 385. (1996), *order on reh'g*, Order No. 888-A, 62 *Fed. Reg.* 12,274 (1997), *FERC Stats and Regs,* ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part, remanded in part on other grounds sub nom.*, *Transmission Access Policy Study Group, et al. v. FERC*, 225 F. 3d 667, Nos. 97-1715 et al (D.C. Cir.), *cert. granted in part*, *New York v. FERC*, 121 S.Ct. 1185 (2001).

Such an interpretation would also be contrary to "the intention of the drafters." The ISO's understanding of the scope of its authority is established by its practice, immediately upon commencement of operations, of billing PG&E for Ancillary Services procured in connection with COTP transactions. (Tr. 521:3-12; 1135:1-18, (R. 02570; 03185); Tr. 527:2-12 (R. 02576); Tr. 1140:25-1141:11; (R. 03190-03191); ISO Exh. 7 (R. 04583); ISO Exh. 18 (R. 04845).)

PG&E's own course of dealing confirms its recognition that, where it acts as Scheduling Coordinator for transactions of others that impose upon the ISO the requirement that it procure Ancillary Services, PG&E bears financial responsibility. For 14 months PG&E without dispute accepted and paid charges for Ancillary Services procured in connection with the COTP. Although the Arbitrator concluded that PG&E did not "discover" the charges until April 1999 (Award at 19), this conclusion is owed no deference because it is unsupported by the record. The Arbitrator acknowledged that PG&E in fact reviewed, however cursorily, preliminary statements that listed the charges in connection with the COTP transactions, *Id.* at 16, and the evidence reflects that the review was far more than "cursory."[10]

[10] Mr. Cowden (who assumed responsibility for reviewing the ISO bills while the Manager of Settlements was on a leave of absence) testified that he carefully reviewed both the Preliminary and Final Settlement Statements PG&E received from ISO. (Tr. 1489:1-3 (R. 03539); 1494:2-7 (R. 03544).) Moreover, the testimony presented by Mr. Cowden, and other PG&E and ISO witnesses, established that PG&E was aware that it was being billed for Ancillary Services with respect to COTP transactions during the first year of ISO operations consistent with the parties' pre-startup agreement. (Tr. 1488:17-25 (R. 03538); 1492:1-1495:6 (R. 03542-03545), ISO Exh. 7 (R. 04583); ISO Exh. 18 (R. 04845).) In fact, Mr. Hoffman testified that Mr. Cowden acknowledged to him during a telephone conversation that he was aware that PG&E was being billed under the COTP Scheduling Coordinator ID for Ancillary Services acquired by the ISO to support COTP Schedules. (Tr. 1151:7-1152:11, (R. 03201-03202).) Despite this knowledge, and his knowledge of the parties' agreement which was conveyed to him by Ms. Peterson before she took her leave, Mr. Cowden, along with PG&E's senior management, authorized and repeatedly paid the costs incurred by the ISO to support the COTP Schedules for a year prior to this dispute arising. (Tr. 1495:7-1496:14, (R. 03545-03546).)

PG&E's disclaimer of knowledge is simply not credible. If PG&E truly believed that it would not be charged anything in connection with its COTP SC ID, even a cursory review of the preliminary settlement statements would have alerted it to a $14 million charge for Ancillary Services. Neither is it credible that PG&E simply "overlooked" the subsequent transfer of that $14 million charge to the final PGAE SC ID settlement statements, the statements upon which it concededly focused its attention.

### D. Cost Causation Principles Support the ISO's Authority to Recover the Cost of Ancillary Services Procured for COTP Transactions from the Scheduling Coordinator for Those Transactions

PG&E's interpretation of the Tariff, accepted by the Arbitrator, would do violence to a core principle of the Commission: that revenue responsibility should, to the extent possible, follow cost causation. That is, a customer's rates should reflect the costs of serving that particular customer. *See Seminole Electric Cooperative, Inc.,* 46 FERC ¶ 61,119, at 61,470-71 (1989). The Commission has left no doubt that consideration of benefits is part of the cost causation evaluation. *See, e.g., Western Mass. Elec. Co*., 66 FERC ¶ 61,167 (1994), *aff'd Western Mass. Elec. Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1999).

The COTP was built so that its participants might obtain additional transfer capacity from the northwest. For the participants to realize those benefits, however, the COTP must be scheduled in coordination with the remainder of the California Oregon Intertie. As the entity scheduling the COTP, the ISO – and PG&E before it – must ensure adequate Ancillary Services to support the scheduled transactions. The COTP participants were well aware of this requirement.  The COA specifically provided that PG&E would integrate the operations of the COTP into its Control Area responsibilities.  (Exh. ISO-2 at 18, COA § 8.2.1 (R. 04476).)  It also provided that, as a condition of scheduling, the COTP participants must have in place arrangements for reserve, regulation, and contingency requirements consistent with Good Utility Practice (defined to include WSCC standards).  (Exh. ISO-2 at 28, COA § 8.4.1 (R. 04486).)  The various Interconnection Agreements required the COTP Participants to schedule self-provided Ancillary Services with PG&E.  (*See, e.g.,*Exh. MID-1 at 43-44 (R. 05938-05939); Exh. TID-2 at 41-42 (R. 06176-06177).)  Ancillary Services not self-provided were purchased from PG&E.  *Id.*

Since the beginning of the ISO's operations, the COTP Participants have continued to enjoy the benefits of coordinated scheduling.  Because, as discussed below, the COTP Participants have failed properly to self-supply the Ancillary Services inexorably tied to that scheduling, the procurement of those Ancillary Services has fallen to the ISO.  The acquisition of those Ancillary Services would not have been necessary *but for* the schedules submitted on behalf of the COTP Participants who, necessarily, were the direct beneficiaries of those acquisitions.  Consistent with the principle of cost-causation, the Scheduling Coordinator responsible for the submission of those schedules must bear the costs thereby imposed, and if there is any ambiguity in the Tariff, it should be resolved in favor of that result.

### E. The Commission's Order on Amendment No. 2 Does Not Imply Any Lack of Authority to Charge Scheduling Coordinators for Ancillary Services in the Control Area

The Arbitrator concluded that his interpretation of the ISO's Tariff authority was reinforced by the Commission's rejection, in its order on Amendment No. 2, of a number of proposed revisions to the Tariff that would have clarified the ISO's Control Area responsibilities. Because the ISO Tariff was filed months prior to the start of ISO operations, at a time when it was anticipated that most, if not all, of the utilities in California would join the ISO, the terms "ISO Controlled Grid" and "ISO Control Area" were not always clearly distinguished. (PG&E Exh. 1 (R. 04257).) Subsequently, many utilities elected not to place their facilities under ISO Operational Control. This created a need for clarification. While, as discussed above, it was clear that the ISO's reliability responsibilities extended throughout the Control Area, it was not clear that schedules were required for all transactions within the Control Area but not on the ISO Controlled Grid. The intent of Amendment No. 2, evident throughout the filing letter,[11] was to clarify that a Scheduling Coordinator was required for *all* transactions within the Control Area whether or not it was on the Controlled Grid. While the disposition of that

[11] For example, the ISO noted

> The design of the California forward markets for Energy and Ancillary Services, and the reliable operation of the ISO Control Area in real-time, is founded on the premise that Generation and Demand within the Control Area, as well as all interties with neighboring Control Areas, are to be scheduled and/or bid with the ISO through Scheduling Coordinators.

(Exh. PG&E-1 at 5 (R. 04621).) The ISO pointed out:

> Without a Scheduling Coordinator to submit the scheduled uses of transmission capacity into, out of, or though the ISO Control Area, whether across the ISO Controlled Grid . . . or other facilities owned by others within the ISO Control Area, the power simply cannot be scheduled with

Amendment might be of some relevance were the transactions at issue "unscheduled," that is pointedly not the case. All of the transactions were scheduled with the ISO, with PG&E serving as the Scheduling Coordinator. Amendment No. 2 simply is not implicated by this dispute.

The language that the Arbitrator quotes reflects this concern. The ISO stated: "Without a requirement that all Schedules be submitted in the requisite form through a Scheduling Coordinator, the ISO would not have . . . the necessary contractual relation by which to charge Ancillary Services." Award at 10. This is simply a statement about the need to have schedules submitted in appropriate form through a Scheduling Coordinator, and does not apply to the COTP. Load served over the COTP was already being scheduled by a Scheduling Coordinator. Amendment No. 2 was not necessary in order for the ISO to charge PG&E for Ancillary Services procured in connection with COTP schedules.

Importantly for this proceeding, neither the transmittal letter nor other evidence suggests that the ISO was concerned about its ability to charge Scheduling Coordinators for costs incurred in connection with transactions scheduled with the ISO, such as subsequently occured with regard to the COTP. Rather, the ISO was specifically concerned with its ability to collect the GMC charge and Ancillary Services costs in connection with Load that was *not*

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the ISO and cannot flow in accordance with NERC and WSCC accepted scheduling practices.

scheduled and for which, accordingly, there was no Scheduling Coordinator. (Exh. PG&E-1 at 7-8 (R. 042163-042164-).)[12]

In rejecting Amendment No. 2, the Commission notably did not address the ISO's existing ability to assess the Grid Management Charge or Ancillary Services charges in connection with scheduled transactions that did not involve the ISO Controlled Grid. 82 FERC ¶ 61,312 (1998).[13] Rather, in explaining its decision, the Commission agreed with statements that the Amendment would expand the *operational control* of the ISO over transmission facilities not under its control. 82 FERC at 62,241. As noted, we are not here dealing with issues of operational control; we are concerned only with responsibility for costs imposed on the ISO as a result of load in the Control Area to which the ISO is providing reliability services.

The Arbitrator concluded that when the Commission further expressed concern that the amendment "would improperly impose additional obligations on Participating Transmission Owners," the "additional obligations" must have included PG&E's payment obligations as the Scheduling Coordinator for the COTP. That conclusion, however, is completely unfounded. The concerns noted by the Commission did not involve payment obligations, but rather obligations

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[12] ISO witnesses testified that the ISO intended, through Amendment No. 2, to implement a more direct scheduling relationship with COTP Participants, but that Amendment No. 2 was not necessary in order to charge PG&E, as Scheduling Coordinator, for Ancillary Services in connection with the COTP Schedules it submitted. (See Tr. 280:3-281:24 (R. – 02329-02330); Tr. 884:17-894:14 (R. 02934-02944).)

[13] The Commission did not even address the ISO's ability to assess charges with regard to unscheduled transactions. Indeed, it *explicitly* reserved the Grid Management Charge for a separate proceeding, *id.,* at 62,241, and in a later proceeding confirmed that decision, *California Independent System Operator Corp.*, 82 FERC ¶ 61,348 (1998).

with respect to third parties that the Participating Transmission Owners were not able to perform under Existing Contracts. *Id.* at 61,242-43.

Finally, the Commission concluded that the amendment was not necessary to address the ISO's operational needs. This determination provides no support for the Arbitrator's conclusion. It is entirely as consistent with a finding that the ISO already possessed the authority to charge for Ancillary Services procured for scheduled transactions that do not involve the ISO Controlled Grid as it is with a contrary finding.[14]

## II. As Scheduling Coordinator for the COTP, PG&E Is Responsible for the Ancillary Services Charges

Under section 2.5.1 and other sections of the ISO Tariff, the ISO is obligated to calculate the costs of its Ancillary Services procurement and to bill those costs to the Scheduling Coordinator who was responsible for causing the costs to be incurred.[15] The Arbitrator, however, concluded that PG&E was not the Scheduling Coordinator for COTP transactions. That conclusion is not only

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[14] If, despite the considerations discussed above, the Commission disagrees that the ISO Tariff provides the authority for the ISO to charge PG&E, as Scheduling Coordinator, for Ancillary Services that the ISO has procured in connection with transactions on the COTP, then the Commission should direct the ISO to make appropriate filings to provide such authority and permit the ISO to recover the costs of the Ancillary Services it has previously provided. *See, e.g., Central Maine Power Co.*, 56 FERC ¶ 61,200 (1991); *PacifiCorp Electric Operations*, 60 FERC ¶ 61,292 (1992); *Central Hudson Gas & Electric Corp.*, 61 FERC ¶ 61,089 (1992).

[15] Section 11.2.3 of the Tariff requires the ISO to "calculate, account for and settle charges and payments for Ancillary Services as set out in sections 2.5.27.1 to 4, and 2.5.28.1 to 4...." (Tr. 889:22-890:4, (R. 02939-02940).) section 2.5.27 specifies which entity should be paid for services provided, and section 2.5.28 describes who should be charged for Ancillary Service procurement costs. Under the Tariff, the "ISO ... allocate[s] the Ancillary Services capacity charges, for both the Day-Ahead and Hour-Ahead Markets, *on an ISO Control Area wide basis* if the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis." (Tariff § 2.5.28 (emphasis added).) Because the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis, the charges are similarly allocated and charged to Scheduling Coordinators on an ISO Control Area wide basis.

inconsistent with PG&E's responsibilities under its Scheduling Coordinator Agreement (Exh. PG&E-6 (R. 04379)), and the Responsible Participating Transmission Owner Agreement (Exh. SMUD-5 (R. 05189)), but also inconsistent with Commission orders (not to mention PG&E's consistent course of conduct since the very inception of ISO operations).

A Scheduling Coordinator is "[a]ny entity certified by the ISO for the purposes of undertaking the functions specified in section 2.2.6 of the ISO Tariff." Tariff, Appendix A. On December 9, 1997, PG&E executed a Scheduling Coordinator Agreement and was certified as a Scheduling Coordinator. (Exh. PG&E-6 (R. 04379); *see also* Tr. 58:25-59:2 (R. 02107-02108); Tr. 512:17-20 R. 02561).) A certified Scheduling Coordinator executes only one Scheduling Coordinator Agreement even though it may be issued several Scheduling Coordinator IDs. (ISO Exh. 18, ¶¶ 3 & 9 (R. 04846, 04848); Tr. 895:1-2, (R. 02945).)[16]

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[16] As Mr. Hoffman explained, "we have the Scheduling Coordinator agreement, and we have currently 65 Scheduling Coordinators who have executed that agreement." (Tr. 810:15-18 (R. 02858): ISO Exh. 18 ¶ 3 (R. 04846).) Each Scheduling Coordinator is often assigned, at its request, more than one Scheduling Coordinator ID:

> It is common practice for the ISO to give multiple Scheduling Coordinator ID's to Scheduling Coordinators. So just because you have multiple SC ID's does not mean you have to have multiple Scheduling Coordinator agreements.
>
> As an example, the power exchange had five Scheduling Coordinator ID's. So what we did for PG&E is they wanted to go ahead and schedule separately the transactions that were on the ISO-controlled grid, and the transactions that were not on the ISO-controlled grid. This gave them the ability to account better, as far as whether the five charges that we discussed should be assessed.
>
> So what they did is they scheduled the bubble transactions and the COTP underneath the COTP ID, and they scheduled the balance of the IA transactions underneath what is called "PGAE." In addition to that,

Nonetheless, the Arbitrator concluded that the Scheduling Coordinator Agreement applies only to transactions taking place within the ISO Controlled Grid and that PG&E did not otherwise agree to act as the Scheduling Coordinator for the COTP transactions. This construction is at odds with the Agreement on its face, which plainly extends to charges that arise from transactions within the ISO Control Area whether or not within the ISO Controlled Grid. The Scheduling Coordinator Agreement requires that Scheduling Coordinators abide by, and perform, *all* the obligations placed on Scheduling Coordinators by the ISO Tariff, without exception. (Tariff at Appendix A, First Revised Sheet 359). Under the ISO Tariff, the first identified responsibility of a Scheduling Coordinator is to pay the ISO's charges in accordance with the Tariff. (Tariff § 2.2.6.1). Because section 2.5.1 of the ISO Tariff makes Scheduling Coordinators responsible for the costs of Ancillary Services, regardless of whether the transaction involves the ISO Controlled Grid, the Scheduling Coordinator Agreement binds the Scheduling Coordinator to pay those charges. At least three other utilities that schedule Grid and non-Grid transactions with the ISO have executed Scheduling Coordinator Agreements identical to that executed by PG&E. (ISO Exh. 11 (Riverside SCA) (R. 04716); ISO Exh. 12 (Anaheim SCA) (R. 04724); ISO Exh. 13 (Pasadena SCA) (R. 04730); Tr. 898:25-899:24; Tr. 904:20-905:6 (R. 02948-02949); Tr. 907:16-908:3 (R. 02954-02955;, 02957-02958).) Under their Scheduling Coordinator

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> [PG&E] now has a third Scheduling Coordinator ID, where it schedules its own utility-retained generation to serve its native load.

(Tr. 810:19-811:13, (R. 02858-59).) Indeed, although PG&E executed only one Scheduling Coordinator Agreement (Tr. 382:19-22 (R. 02431); Tr. 512:17-20,(R. 02561)), it currently utilizes three Scheduling Coordinator IDs to Schedule power flows for which it is responsible, *i.e.*, PCG1, PGAE and COTP. (ISO Exh. 18, ¶ 9; (R. 04848).)

Agreements they fulfill their Ancillary Service obligations regardless of whether the particular schedule is on or off the grid. *Id.*

Indeed, the Commission has twice affirmed PG&E's Scheduling Coordinator obligations for the COTP. On October 30, 2000, PG&E attempted to amend the COA and remove itself from its role as the COTP Scheduling Coordinator. (Exh. ISO-3 (R. 04547); ISO Exh. 14 (R. 04736).) Under the COA, PG&E had the obligation to schedule COTP transactions. (Exh. ISO-2 (R. 04452).)[17] The Commission decided that PG&E was the COTP Scheduling Coordinator and could not avoid its obligations without properly assigning its role to another entity (which it has never done):

> PG&E purports to merely reflect the reality of its changing role, and the new role of the ISO, under electric restructuring in California. However, PG&E's filing is more than a mere ministerial filing to substitute reference to PG&E with references to the ISO with regard to duties *currently* being performed by the ISO. It is apparent from PG&E's filing – and its answer removes any doubt – that PG&E also proposes to cease performing scheduling functions that it is currently performing for COTP participants. . . . *We agree with the Intervenors that PG&E is, in effect, attempting to assign its scheduling coordinator duties and responsibilities to some other entity. . . .*

(*Pacific Gas and Elec. Co.*, 93 FERC ¶ 61,322 at 62,104-05 (2000) (emphasis added) (R. 04378).)

On January 29, 2001, PG&E filed a Request for Rehearing, specifically

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[17] Under the COA, PG&E has responsibilities for the coordinated operation of the COTP and the Pacific AC Intertie, including such matters as "receiving schedules of COTP transactions and coordinating them with the control area operator in the Pacific Northwest, coordinating maintenance, approving clearances, applying curtailment priorities, applying curtailment allocations, and advising those using the COTP of the reasons for curtailments." (PG&E Exh. 4 at 2-3 (R. 04565-66) (*Pacific Gas and Electric Co.*, FERC Docket No. ER01-276-000 (2000).)

requesting that the Commission reconsider its finding that "PG&E was attempting to 'assign' to a third party scheduling coordinator duties and obligations under the COA." (ISO Exh. 4 at 1 (R. 04556).) The Commission declined to do so. (*Pacific Gas and Electric Company*, 94 FERC ¶ 61,204 at 61,770 (2001) (R. 04565).)

Despite this clear language, the Arbitrator concluded that the Commission did not mean what it said. He concluded that the Commission was aware that PG&E was not willing to be the Scheduling Coordinator for the COTP, and therefore its reference to PG&E's effort "to assign its scheduling coordinator duties and responsibilities . . . cannot be regarded as a recognition that PG&E is the COTP Scheduling Coordinator." Award at 17.

It is difficult to understand what else the Commission could have meant when it said that "PG&E was attempting to 'assign' to a third party scheduling coordinator duties and obligations under the COA." The term Scheduling Coordinator (whether capitalized or not) was not used as a term of art prior to the filing of the ISO Tariff. (Tr. 158:25-159:2 (R. 02207-02208).) It "was a new term that became defined in the ISO Tariff. It was not a term that PG&E utilized to describe its responsibilities in performing its Control Area and scheduling functions with regard to the COTP prior to ISO Start-up." (Tr. 89:16-90:1 (R. 02138-02139).)

Contrary to the Arbitrator's premise, PG&E's responsibilities as COTP Scheduling Coordinator do not depend on the existence of a "meeting of the minds" that it act in this capacity, or even its willingness to serve as the COTP Scheduling Coordinator.[18] Under the ISO Tariff, only a Scheduling Coordinator

[18] The Arbitrator's finding that there was no meeting of the minds is not supported by the evidence. If any thing, the evidence supports an oral agreement. Although the Arbitrator

can submit schedules. ISO Tariff § 2.2.3. The COA requires PG&E to schedule the COTP transactions. Because of the integrated nature of the COTP and the ISO Controlled Grid, (Tr. 82:4-9, (R. 02131)), PG&E can only do so through the ISO. As the entity submitting schedules for the COTP, PG&E necessarily is the COTP Scheduling Coordinator.

The Commission has recently held that it is the submission of schedules, not the subjective intent of the entity submitting the schedules, that determines whether the entity is the Scheduling Coordinator. In *California Independent System Operator Corp.*, 97 FERC ¶ 61,151 (2001), the Commission addressed the responsibility of the California Department of Water Resources ("DWR") for transactions that it undertook as guarantor for Southern California Edison Company and Pacific Gas and Electric Company. The Commission ruled that DWR "functions as the Scheduling Coordinator" and therefore was financially responsible for any transactions scheduled by the ISO on its behalf:

> We note that DWR has already executed a Scheduling Coordinator Agreement with the ISO. This agreement includes, among other things, an obligation by DWR to abide by and perform all of the obligations under the ISO Tariff, without limitation. This includes an obligation to pay for

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correctly observes that an oral agreement cannot provide the basis for assessing charges (Award at 14, citing *PacifiCorp Electric Operations*, 60 FERC ¶ 61,200 (1992)), it can inform the Commission's interpretation of PG&E's Scheduling Coordinator responsibilities. The Arbitrator relied solely on documentary evidence (Award at 15) and ignored the sworn testimony of three ISO witnesses who testified that they were present at a meeting in March 1998 at which PG&E agreed to schedule the COTP transactions and to reimburse the ISO for the costs it incurred to procure Ancillary Services in the absence of adequate self-provision. Based on their first hand account, the agreement reached by the parties is clear. (Tr. 233:19-235:14 (R. 02282-02284); Tr. 237:17-241:4 (R. 02286-02290); Tr. 812:19-813:16 (R. 02860-02861); Tr. 1190:21-1192:21 (R. 03140-03142).) The contrary evidence is from PG&E witnesses who testified that they had an "understanding" that they would not be billed for any charges in connection with the COTP transactions. (Tr. 41:16-42:1 (R. 02090-02091); 451:21-25 (R. 02500).) None of these witnesses, however, were at the key meeting that took place at ISO's offices in mid March 1998 when agreement on what PG&E would and would not be billed was reached. The Arbitrator's rejection of the ISO's sworn testimony based on hearsay and second-hand "understandings" is not entitled to deference.

> scheduled and unscheduled transactions made on the Scheduling Coordinator's behalf by the ISO. . . . Although this agreement was entered into prior to SoCal Edison and PG&E losing their creditworthy status, nothing in the agreement limits the scope to DWR's scheduling of its own load, or distinguishes DWR's functioning as the creditworthy party for the net short position for the non-creditworthy UDCs. . . .
>
> Therefore, because DWR has assumed responsibility for purchases by the ISO, and because DWR functions as a Scheduling Coordinator for this net short position of PG&E and SoCal Edison, DWR must abide by the requirements of the ISO Tariff and the Scheduling Coordinator Agreement.

97 FERC at 61,659. By the same reasoning, PG&E is the Scheduling Coordinator and financially responsible for the non-ISO Controlled Grid transactions at issue here.

## III. PG&E Was Not Excused From Its Obligation to Pay for Ancillary Services by Virtue of "Self-Provision" of the Ancillary Services Required in Connection With the COTP Schedules

Although the Arbitrator did not rely on self-provision of Ancillary Services in his decision, he concluded that the self-provision arrangements of the COA remained in place following startup, and he is critical of the ISO for its failure to assume the responsibility to determine whether the self-provision procedures continued to be in place after the ISO succeeded to PG&E Control Area responsibilities. This represents a fundamental misunderstanding of how responsibilities are allocated, and the compelling practical reasons for this allocation.

Because of the practical exigencies of operation, the ISO must receive verifiable, timely information establishing the adequate self-provision of Ancillary Services in the Schedules submitted to it in order to credit that self-provision, s*ee*, *e.g.*, Tr. 646:13-23, (R. 02694). That is precisely what the ISO Tariff requires. ISO Tariff § 2.5.20.2. Thus, if a Scheduling Coordinator wishes to avoid imposing acquisition responsibility on the ISO, it must certify self-provision in the Schedules that it provides to the ISO. The complex demands of hour-to-hour scheduling necessitate that such information flow from the Scheduling Coordinator to the ISO. The ISO simply cannot perform such scheduling of Ancillary Services while simultaneously being required to take time out to query individual Scheduling Coordinators who for whatever reason do not report self-provision. Absent a Scheduling Coordinator's report of self-provision, the only prudent course of action available to the ISO is to procure the necessary additional Ancillary Services. (Tr. 1274:16-1275:16, (R. 03324-03325).) In its role as Control Area operator, the ISO must assume that Ancillary Services are not being provided unless it is informed otherwise, and it is a simple matter for Scheduling Coordinators to do so.

Here, as the Arbitrator found, neither PG&E nor the COTP participants provided the ISO with *any* information regarding the purported self-provision of Ancillary Services when the Schedules were submitted. Award at 15; *see also* ISO Exh. 24 (R. 04919). Moreover, the COTP participants were incapable of self-providing all but a small portion of the Ancillary Services in question. The lion's share of the costs incurred by the ISO to support the deficient COTP Schedules was for Regulation service. (Joint Exh. 1(R. 04252).)[19] Only entities

[19] Of the $14,172,337.08 in costs that the ISO incurred to support COTP Schedules during the first year of operations (Joint Exh. 1 (R. 04252)), approximately $11 million was incurred to procure Regulation. (Tr. 1074:24-1075:9 (R. 03124-03125).) In addition, from May 1, 1999 through June 30, 2001, of the $40,376,867 in Ancillary and other service costs incurred to support COTP Schedules, more than 90 percent or $36,542,762 was incurred to procure Regulation. (Tr. 1074:24-1075:9; (R. 03124-03125); Joint Exh. 1 (R. 04252).) Thus, of the approximately $54.5

that are certified by the ISO to provide Regulation[20] and have equipment in place that allows the ISO to control the generating unit may self-provide this particular Ancillary Service. (ISO Tariff § 2.5.3.1 & Appendix A.) At all times, it is the ISO, and not either PG&E or the Intervenors, that is required to maintain sufficient Generating Units that are "immediately responsive to [Automatic Generation Control] in order to provide sufficient Regulation to allow the system to meet WSCC and NERC criteria." (Tariff § 2.5.3.1.)

The evidence established that none of the COTP participants (with the recent exception of SMUD[21]) had been certified by the ISO to self-provide Regulation service, or had provided the ISO with *any* Automatic Generation Control over their respective generating units. (ISO Exh. 16 ¶ 14 (R. 04842-43).) Indeed (except for SMUD), none of them had arrangements to self-provide Regulation under their Interconnection Agreements. (Exh. MID-1 at 43-44 (R. 05938-05939); Exh. TID-2 at 41-42 (R. 06176-06177).) There is also no evidence that PG&E was providing Regulation on their behalf. Because Regulation could not be self-provided under these circumstances, the ISO had to

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million in costs incurred through June 30, 2001, approximately $47.5 million was incurred by the ISO to procure Regulation.

[20] Regulation is critical for ensuring that the frequency is maintained at 60 cycles within the Control Area. When system frequency deviates from 60 cycles, there is the possibility that motors and other electronic devices could be damaged and that frequency in other Control Areas within the Western United States could be adversely affected. (Tr. 1273:10-24, (R. 03323).) The first line of defense to prevent frequency deviations is Regulation because it operates on a four-second control cycle. (Tr. 1156:20-23 (R. 03206).) As soon as frequency begins to decay within the Control Area, generating units with AGC Regulation immediately and automatically respond to restore it. (Tr. 1156:20-1157:3 (R. 03206-03207).) Without Automatic Generation Control over generating units, ISO is unable to call upon Regulation to respond to those deviations in the Control Area. (Tr. 1280:19-22 (R. 03330).)

[21] Since December 2000 (the date SMUD was certified to self-provide Regulation), the ISO has fully credited SMUD's self-provision of Regulation and adjusted its procurement accordingly.

procure it to support the COTP Schedules PG&E submitted in order to meet its Control Area Operator and Tariff responsibilities.

## IV. PG&E's Claim Is Time-Barred

Under the ISO Tariff and the policies articulated by the Commission, PG&E's claim for the $14 million in charges that it previously paid is time-barred. As explained by Mr. Cowden, during the period the charges at issue were billed and paid by PG&E, the ISO Tariff only permitted market participants to dispute charges assessed on the daily Preliminary Settlement Statements. (Tr. 1498:1-7, (R. 03548).) Under the relevant Tariff provisions in effect at that time, Scheduling Coordinators had ten (10) calendar days to object to the payment of a Preliminary Settlement Statement. (Tr. 545:6-15; 1172:14-21 (R. 02594; 03222).)[22] PG&E did not do so. Having failed to assert timely challenges, its claims are time-barred.

The Arbitrator excused PG&E's failure to object to charges on a timely basis, however, based on his judgment that PG&E did not discover the disputed charges until April 1999. As discussed above, the evidence supporting that finding is not credible. Even if PG&E did not discover the charges until that date, however, it should not be exempted from the time limitations unless, at a minimum, its failure was reasonable and excusable. No such claim can credibly be made here. The amount at issue is not insignificant (and therefore likely to

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[22] The ISO Tariff was amended in 2000 to include procedures for disputing both Preliminary and Final Settlement Statements. "Each Scheduling Coordinator shall have a period of eight (8) Business Days from issuance of a Preliminary Settlement Statement during which it may review the Preliminary Settlement Statement and notify the ISO of any errors." (Tariff § 11.6.1.2.) Further, "[e]ach Scheduling Coordinator shall have a period of ten (10) Business Days from the issuance of the Final Settlement Statement during which it may review the Incremental Changes on the Final Settlement Statement and notify the ISO of any errors." (Tariff § 11.6.1.3.)

escape notice), and PG&E has conceded that it closely scrutinized transactions under its principal ID Code, the very statements to which these charges were transferred.

The time limitations of the ISO Tariff should not be waived, and PG&E's claims should be barred.

## CONCLUSION

For the foregoing reasons, the Commission should reverse the decision of the Arbitrator and issue an order that:

(1) permits the Market Participants to retain the $14,172,337.08 paid by PG&E for Ancillary Services and other costs during the period April 1998 through April 1999;

(2) permits the ISO to recover from PG&E an amount of at least $40,376,867 for Ancillary Services incurred to support COTP Schedules from May 1999 through June 30, 2001, plus interest;

(3) declares that PG&E is responsible to pay for any Ancillary and related services the ISO has procured since June 30, 2001, or will in the future procure, to support COTP Schedules submitted to it by PG&E; and

(4) declares that PG&E is required to continue to act as the COTP Scheduling Coordinator and provide the ISO with any Scheduling information or data necessary to enable the ISO to discharge its obligations under the Tariff and as the certified WSCC Control Area Operator until such time as the Commission authorizes otherwise.

Respectfully submitted,

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