UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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California Independent System	)	ER01-____-000
Operator Corporation	)	
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DIRECT TESTIMONY OF
TRENT A. CARLSON
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

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

A. My name is Trent Carlson. I am employed by the California Independent System Operator Corporation ("ISO") as Director of Operations Support and Training. My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES?

A. As Director of the Operations Support and Training Department, I am responsible for directing a team of engineering and operations experts in the development and maintenance of all Operating Procedures, providing dispatch support to control room operators, coordinating electrical emergency response efforts, administering the ISO's master training program, and managing the research and development efforts at the ISO related to advancing the market front-end approach to grid operations.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am an electrical engineer with over 17 years of experience in power system operations and planning. I have a Masters Degree in Electrical Engineering from New Mexico State University in Las Cruces, New Mexico.

My professional experience includes working at a utility in western Kansas and a consulting firm in northern California. While at Sunflower Electric Power Corporation, my system planning and operations engineering assignments involved performing power flow, short-circuit, transient stability, and production cost analyses, as well as joint studies with neighboring utilities in the Southwest Power Pool ("SPP") and the Mid-Continent Area Power Pool ("MAPP"). System protection duties included design of relay applications and controls for both 69-kV and 115-kV transmission systems, as well as Project Manager responsibilities for the specification, testing, and installation of the company's first Energy Management System ("EMS"). I also served as the corporation's representative on several SPP and Missouri-Kansas Power Pool ("MOKAN") committees.

While at the consulting firm of Resource Management International, I managed a small group of engineers/economists focused on system studies, strategic planning assignments, power marketing assessments, contract negotiations, and provision of expert witness services. Assignments included the development of the Philippines' first open access transmission tariff; preparation of power supply Requests for Proposals ("RFPs"); system studies in both eastern and western interconnections of the U.S., including studies of the Pacific AC/DC Intertie; expert witness testimony in both civil and administrative courts on issues pertinent to system operations, transmission planning, and transfer capability analysis; and the negotiation of interconnection agreements, participation agreements, operation and maintenance agreements, and agreements related to transmission service and assignments of transmission entitlements.

Since joining the ISO, initially as an interim staff contractor, I was assigned to the Scheduling Applications ("SA") development team, working on the preparation of functional descriptions for the detailed statements of work, reviewing technical descriptions, and assisting with the preparation of test scripts for SA modules. This role was expanded to include participation in the development of the Scheduling Infrastructure ("SI") and interfaces with the other subsystems. Interim staff assignments later included assisting with the preparation of the various versions of the ISO Tariff, beginning with the original March 1997 draft filed at the

Federal Energy Regulatory Commission ("FERC"), and taking the lead on preparing some of the original ISO Protocols (*e.g.*, the Schedules & Bids Protocol and the Scheduling Protocol). The interim staff assignment transitioned into a full-time staff position in the Operations and Engineering Department in September of 1997. Prior to assuming my current position as the Director of Operations Support and Training Department, I was the Senior Engineer in the Grid Operations Department.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY?

A. Yes. Prior to joining the ISO, I testified as an expert witness in the Superior Courts of the County of San Francisco and the County of Los Angeles, and before the Hawaii Public Utilities Commission. I have testified on behalf of the ISO before the California Public Utilities Commission. I have not previously testified before FERC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is twofold: First, to discuss the ISO's responsibilities as Control Area operator in accordance with North American Electric Reliability Council ("NERC") policies and standards and Western Systems Coordinating Council ("WSCC") criteria. These responsibilities create the necessity for the ISO to obtain complete information on Control Area Gross Load, and justify charging entities on a Control Area Gross Load basis for the Control Area Services element of the Grid Management Charge ("GMC"). I will explain the ISO's responsibilities as Control Area operator, and the implication of these responsibilities for the GMC. I also will touch on related cost-responsibility concerns. Second, I will describe several of the services the ISO provides under the Control Area Services element of the GMC from an operations point of view.

Q. DO YOU USE ANY SPECIAL TERMS IN YOUR TESTIMONY?

A. Yes. Unless otherwise indicated, capitalized terms are as defined in Appendix A, Master Definitions Supplement, to the ISO Tariff.

I. THE ISO'S CONTROL AREA RESPONSIBILITIES

Q. WHAT ARE THE ISO'S PRIMARY RESPONSIBILITIES?

A. One primary responsibility of being the Control Area operator is the ISO's provision of scheduling services for the Control Area. The scheduling regime requires that Demand and Generation be separately scheduled. The ISO also has a Balanced Schedule requirement which means the forward schedules submitted by Scheduling Coordinators ("SCs") must be balanced (i.e., the scheduled Demand must match the scheduled Generation). Furthermore, as Control Area operator, the ISO must ensure that system balance is maintained in real time.

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT THE ISO MUST ENSURE THAT SYSTEM BALANCE IS MAINTAINED?

A. As I just mentioned, the market design in California requires that SCs must submit Balanced Schedules to the ISO. This means the SCs must submit Schedules in which injections into the system (Generation from units located within the Control Area and imports from external Control Areas) match withdrawals from the system (Demand of Loads located within the Control Area and exports to external Control Areas). To the extent there are net deviations from Balanced Schedules in real time, the ISO has the responsibility to ensure the system remains in balance by adjusting resources, including the dispatch of Imbalance Energy from capacity reserves. This real time matching of Generation, Demand, imports, and exports occurs on a Control Area basis. That is to say, SCs must match Generation, most but not all of which is connected at the transmission level, with Demand from Loads connected primarily but not exclusively at the distribution level, in Balanced Schedules submitted to the ISO prior to real time. During real time, SCs may deviate from their Balanced Schedules. To the extent there are any net deviations, the ISO dispatches Imbalance Energy to make up any differences to satisfy NERC and WSCC reliability criteria (which I will describe below). Maintaining the balance between Load and Generation within the Control Area also includes use of the facilities required to deliver the electrical output to Load (*i.e.*, transmission and distribution facilities) reliably. The costs of these transmission and distribution facilities are not recovered in the GMC.

Q. WHAT ARE THE ROLES OF UTILITY DISTRIBUTION COMPANIES AND SCHEDULING COORDINATORS IN THE CONTEXT OF THIS ISO RESPONSIBILITY TO MAINTAIN SYSTEM BALANCE IN REAL TIME?

A. The Utility Distribution Companies ("UDCs") operate Distribution Systems. In addition, the UDCs provide electric service to customers that have not elected to obtain service from a competing electric service provider ("ESP"). Each UDC relies on an SC to submit Balanced Schedules, and to report meter data, to the ISO. To the extent the SC's metered Generation and Demand differs from that submitted in its Balanced Schedule, the SC is deemed to have purchased, or sold, Imbalance Energy from, or to, the ISO. Thus, the SCs and the UDCs do not themselves undertake responsibility for balancing Generation and Demand in real time.

Q. DOES EACH UDC MAINTAIN SYSTEM BALANCE IN ITS DISTRIBUTION SYSTEM?

A. No. The UDCs have a responsibility to operate their Distribution Systems reliably. In the California system, however, the UDCs are not the Control Area operators. Therefore, it is the ISO that maintains overall system reliability and is responsible for maintaining system balance within and connected to other Control Areas, as discussed above. The ISO satisfies these requirements first by requiring SCs to submit Balanced Schedules, and then, in real time, by calling on resources bid into the Imbalance Energy market.

Q. IS THE ISO CONTROLLED GRID USED TO FURNISH ANCILLARY SERVICES AND IMBALANCE ENERGY?

A. Yes. Subject to transmission constraints and the requirement that Ancillary Services must be dispersed geographically, the ISO arranges and accounts for the supply of Ancillary Services and Imbalance Energy from the most economic sources.

Q. WHAT OTHER PRIMARY RESPONSIBILITIES DOES THE ISO HAVE IN ADDITION TO PROVIDING SCHEDULING SERVICES AND MAINTAINING SYSTEM BALANCE IN REAL TIME?

A. Another fundamental responsibility of being the Control Area operator is that the ISO must "ensure the efficient use and reliable operation of the transmission grid consistent with the achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating

Council and the North American Electric Reliability Council". California Public Utilities Code Section 345. The ISO is a member of both the WSCC and the NERC.

The ISO operates the ISO Controlled Grid, which includes the transmission systems of the California investor-owned utilities (Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E")), and provides open and non-discriminatory access to these facilities, while at the same time honoring existing contractual arrangements. In addition, the ISO is the Control Area operator for the entire system within its electrical boundaries (defined by interchange metering with adjacent Control Areas such as Bonneville Power Administration, Sierra Pacific Power Company, Los Angeles Department of Water and Power, Arizona Public Service Company, and others), which encompasses the ISO Controlled Grid, the Distribution Systems of the California investor-owned utilities, and other transmission and distribution systems within California, including the systems of municipal, state and federal governmental entities. As Control Area operator, the ISO is required to abide by WSCC criteria and NERC policies. The WSCC defines a Control Area as: "An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection." *WSCC Reliability Criteria Definitions*, August 2000.

Q. WHAT ARE THE POLICIES, STANDARDS AND CRITERIA THAT DEFINE THE ISO'S CORE SET OF RESPONSIBILITIES WITH RESPECT TO MAINTAINING RELIABILITY?

A. The WSCC and NERC, as reliability organizations, develop standards, policies and criteria that apply to their members in relation to each member's particular roles and responsibilities. These standards, policies and criteria apply to the ISO, as a member of both of these organizations, in relation to its Operational Control of the ISO Controlled Grid and its standing as a Control Area operator. For example, each Control Area operator within the interconnection has the responsibility to plan and coordinate the reliability services associated with the power systems existing within its electrical boundaries, and the interaction of these power systems with neighboring Control Areas.

Q. HOW DOES THE ISO UNDERTAKE ITS RESPONSIBILITY TO ENSURE WSCC AND NERC CRITERIA ARE MET?

A. To ensure that WSCC and NERC planning and operating criteria are met, the ISO undertakes several activities.

First, consistent with its obligations as a provider of open-access transmission, and in addition to performing Congestion Management on a daily and hourly basis, the ISO evaluates the multi-year transmission plans of Participating Transmission Owners ("PTOs") and participates in several planning studies that are coordinated within the membership of the WSCC. The ISO also performs annual and multi-year studies to determine the need for Reliability Must-Run Generation contracts to address specific reliability requirements.

Second, consistent with its obligations both as a Control Area operator and as the Ancillary Services provider of last resort, the ISO procures through Day-Ahead and Hour-Ahead Ancillary Service markets adequate levels of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve capacity to satisfy WSCC Minimum Operating Reliability Criteria ("MORC") requirements. The MORC criteria are include with this filing as Ex. No. ISO-11. The WSCC MORC requires that "[e]ach control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load." As well, MORC requires that "[e]ach control area shall maintain minimum operating reserve…." MORC states moreover that "[e]ach entity operating transmission, generation or distribution facilities shall either operate a control area or make arrangements to be included in a control area operated by another entity. All generation, transmission and load operating within the Western Interconnection shall be included within the metered boundaries of a WSCC control area. Control areas are ultimately responsible for ensuring that the total generation is properly matched to total load in the Interconnection." The ISO's Control Area responsibilities to arrange and call upon Ancillary Services can be found in MORC, Section 1, subsection A, beginning at page 2. The introduction to subsection A of MORC Section 1 explains that "reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies.” Subsection A goes on to set forth the Control Area requirements upon which the ISO has defined its Ancillary Services; for example, MORC requires:

- Regulating reserve that is "immediately responsive to automatic generation control to provide sufficient regulating margin to allow the control area to meet NERC's *Control Performance Criteria*" (the ISO calls on Regulation, as defined in its tariff, to satisfy this requirement);
- Contingency reserve "to reduce area control error (ACE) to zero within ten minutes" (the ISO calls on Spinning Reserve and Non-Spinning Reserve, as defined in its tariff, to satisfy this requirement); and
- "After the occurrence of any event necessitating the use of operating reserve, that [operating reserve] shall be restored as promptly as practicable (the ISO also calls on Replacement Reserve to satisfy this requirement). According to MORC, "the time taken to restore reserves shall not exceed 60 minutes” (the ISO will not validate bid or self-provided Replacement Reserve with time delays specified for a Settlement Period in excess of 60 minutes).

Third, consistent with its obligations as a Control Area operator to ensure that system balance is maintained, the ISO operates a real time Imbalance Energy market to ensure that all Generation and all Load within the Control Area are balanced on a moment-to-moment basis, taking into account interchange with other Control Areas. As a Control Area operator, the ISO must avoid burdening neighboring Control Areas to the greatest extent possible. This is accomplished, in part, by properly arranging Operating Reserves, scheduling interchange and maintaining power flows within established operating limits, and providing adequate contribution to interconnection frequency regulation.

Q. ARE THERE PENALTIES FOR FAILURE TO MEET THESE CRITERIA?

A. On September 1, 1999, the WSCC Reliability Management System ("RMS") Phase I system of monetary penalties and sanctions went into full force and effect. These monetary fines are levied against the Control Area operator for violation of the reliability criteria. It has, therefore, become all the more critical for the ISO, as a Control Area operator, to have timely and accurate schedules of total Load and Generation within the Control Area and to schedule interchange transactions with other Control Areas on a timely and consistent basis in order to avoid the imposition of such monetary fines. Moreover, this new regime of WSCC RMS penalties and sanctions will make it all the more critical to have accurate information on the schedules, status and operation of all resources within the Control Area. Without such information, the allocation of any such penalties and sanctions from the ISO to the entity that caused the reliability criteria violation will be imprecise.

Q. WHY IS CURRENT INFORMATION ON THE STATUS OF GENERATING UNITS AND LOADS SO IMPORTANT?

A. With or without the WSCC RMS penalties and sanctions, the need for accurate information on the schedules, status, and operation of resources (*i.e.*, Generating

Units and Loads) within the Control Area is clear. To illustrate the point, consider the fact that Demand within the Control Area, in real time, is calculated as the difference between Generation and net interchange (*i.e.*, Demand = Generation - Net Interchange, with exports being positive). The extent to which the output from Generating Units is not monitored by the Control Area EMS is the extent to which Demand within the Control Area is underestimated. The extent to which Demand is underestimated is the extent to which Ancillary Services are insufficiently provided. Similarly, the extent to which Loads are not metered and the Demand unreported is the extent to which the allocation of Ancillary Services costs will be shifted to other Market Participants since the ISO bills Market Participants for Ancillary Services based on metered Demand.

Q. WHAT ARE THE ISO'S RESPONSIBILITIES ASSOCIATED WITH ANCILLARY SERVICES?

A. To meet WSCC and NERC operating criteria, the ISO, as Control Area operator, must ensure that adequate capacity reserves are available at all times. To the extent possible, the ISO undertakes this responsibility using a market-based approach, through running Day-Ahead and Hour-Ahead markets for Ancillary Services (*i.e.*, Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve). Once arranged, the ISO will, if necessary, call on these capacity reserves in real time to satisfy WSCC and NERC criteria.

The ISO makes payments for Ancillary Services to Scheduling Coordinators ("SCs") that successfully bid their resources into the ISO's Day-Ahead and Hour-Ahead markets. The ISO assigns obligations for Ancillary Services to SCs based on the metered Demand of the Loads they represent. SCs have two options for meeting their Ancillary Services obligations: they can self-provide the requisite levels of reserves or they can purchase the reserves from the ISO.

Q. ON WHAT BASIS DOES THE ISO DETERMINE ITS ANCILLARY SERVICES REQUIREMENTS?

A. The required amounts of capacity reserve are based on the ISO's "Load Responsibility", as this term is defined and applied within the WSCC MORC. The WSCC MORC defines "Load Responsibility" as "A control area's firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier". Ex. No. ISO-11. The WSCC term "Load Responsibility" is applicable to Control Area operators.

Q. HOW ARE THE COMPONENTS OF LOAD RESPONSIBILITY DETERMINED IN REAL TIME?

A. The Demand for Energy within a Control Area must be calculated in real time, whereas firm sales of Energy to other Control Areas (*i.e.*, exports) and firm purchases of Energy from other Control Areas (*i.e.*, imports) are accounted as interchange. Control Area operators compare these import and export quantities to assure, among other things, that one or the other is providing the requisite amounts of reserves to support the transactions of Energy. To calculate the total amount of Demand for Energy within its Control Area in real time, the ISO must have information on the output of individual Generating Units within its Control Area in addition to the information it has on imports and exports with other Control Areas. During real time, the ISO's EMS scans the individual points of interchange with other Control Areas and the output from individual Generating Units to arrive at the calculated total amount of Demand for Energy within the Control Area (*i.e.*, in real-time, Demand = Generation - Net Interchange, with exports being positive). The Demand that is calculated in real time can then be trended forward with appropriate adjustments (*e.g.*, taking into account weather, day of week, etc.), to establish the basis on which the ISO sets its requirements for Ancillary Services in the Day-Ahead and Hour-Ahead scheduling processes. Therefore, accurate information on Generation is essential in the ISO's meeting its responsibilities as Control Area operator and in fulfilling its responsibilities as provider of last resort in Ancillary Services markets.

Q. WHY DOES THE ISO CALCULATE DEMAND IN REAL TIME, INSTEAD OF RELYING ON LOAD METERING DATA?

A. Scanning the multitude of individual Loads directly with the ISO's EMS in real time, as opposed to scanning Generating Units and interties with other Control Areas, is impractical at this time due to technological limitations and prohibitive costs when compared to the alternative of scanning several hundred Generating Units, plus the interties. Most of the information from Load meters is not available to the ISO until several weeks after real time.

Q. ARE YOU FAMILIAR WITH THE TERM "BEHIND-THE-METER" AS APPLIED IN THE CONTEXT OF GENERATORS AND LOADS?

A. Yes. The term "behind-the-meter" generally refers to situations in which a Load's electrical consumption cannot be distinguished from a Generating Unit's simultaneous production of electricity; since both are measured with only one meter. For example, the Demand of a Load might have been 10 MW at the same time a Generating Unit produced 6 MW. In this example, the Load behind-the-meter appears to be 4 MW and the Generation behind-the-meter appears to be zero.

Q. WHAT IS THE RELATIONSHIP BETWEEN BEHIND-THE-METER LOAD AND THE ISO'S RESPONSIBILITIES FOR ARRANGING ANCILLARY SERVICES AND MAINTAINING SYSTEM BALANCE?

A. Some parties may argue that none of their behind-the-meter Generating Units or Loads use the ISO Controlled Grid or any of the ISO's Control Area services. This is not the case. Instead, those systems operating within a Control Area are inextricably and synchronously integrated with one another, in that almost every transaction has at least some effect on ISO operations. These transmission facilities are located within the metered boundaries of the Control Area operated by the ISO and have, almost without exception, an effect on ISO operations.

For example, assume a Generating Unit serving behind-the-meter Load pursuant to a contract is generating 25 MW of electricity, none of which is deemed under the contract to "use" the ISO Controlled Grid. Assume also that an unexpected event occurs and the Generating Unit's 25 MW of Generation is disconnected from the system. The ISO's Area Control Error ("ACE") then changes in this amount (plus the changes in system losses that will have occurred due to the disconnection of the Generation). At the scan rate of the ISO's EMS, Participating Generators providing Regulation (*i.e.*, enabled Automatic Generation Control) would be issued control signals to adjust their output for the 25 MW deficiency. To return the Regulation units to their preferred operating points, the ISO would then call on resources, in price merit order, from the real time balancing energy market. Assuming further that the Generating Unit had its Generation monitored by the ISO's EMS, the ISO also would have detected the cause of the ACE excursion. On the other hand, if the Generating Unit did <u>not</u> have its Generation being monitored by the ISO EMS, the disconnection of the

Generation still would have caused ACE to change by the same amount; the only difference would be that the ISO would not have any information on what event occurred or where (unless the Generating Unit's operators get the information to the ISO Control Area operators).

Q. YOU STATED THAT THE NATURE OF INTERCONNECTED SYSTEMS IS SUCH THAT ALMOST EVERY TRANSACTION INVOLVING A GENERATING UNIT SERVIING BEHIND-THE-METER LOAD HAS AT LEAST SOME EFFECT ON ISO OPERATIONS. ARE THERE ANY SUCH TRANSACTIONS THAT DO NOT AFFECT ISO OPERATIONS?

A. If a Generating Unit is electrically isolated from the ISO Controlled Grid, that is, if the Generating Unit is not connected to the interconnected grid, it will not affect the ISO Control Area or ISO Controlled Grid. There is, moreover, a very narrow circumstance that could exist in which a Generating Unit transaction may have little to no effect on the ISO Control Area or ISO Controlled Grid even if it is not isolated from the interconnected grid. The circumstance is one in which the energy transmitted from a Generating Unit to behind-the-meter Load does not alter in any way the energy flowing on the ISO Controlled Grid and the Demand of the Load is subject to an automatic curtailment scheme that would disconnect or curtail the Load simultaneously in the exact amount as the disconnection or curtailment of the Generating Unit. Under this circumstance, the Generating Unit transaction could be deemed not to affect the ISO Control Area or the ISO Controlled Grid. In this example, the ISO would not carry reserves for the Load, or provide Imbalance Energy to it, because the Load would not exist anytime that the associated Generating Unit is not operating.

Even in this narrowly focused example, however, ISO Control Area operations would still be affected inasmuch as the ISO would have to: (1) account for the amount of Demand that is connected to the system but that is controlled by an automated curtailment scheme (*i.e.*, to avoid including it in the ISO's calculation of Ancillary Service requirements and obligations); and (2) be able to monitor the status of the automated curtailment scheme (*i.e.*, when the scheme is unavailable but the Load is still connected, the Demand would be included in the ISO's calculation of Ancillary Service requirements and obligations). Therefore, there are costs borne by the ISO to plan for, monitor and support these automated schemes as connected within the electrical boundaries of the ISO Control Area.

Q. ARE THE ISO'S RESPONSIBILITIES LIMITED TO OPERATION OF THE ISO CONTROLLED GRID?

A. No. As explained earlier, the ISO is a NERC sanctioned Control Area operator. As such, the ISO must ensure that it satisfies all applicable operating and planning criteria for all Load within the Control Area, not just that located on the ISO Controlled Grid. Therefore, the ISO must be aware of all transactions that occur both on the ISO Controlled Grid and in the ISO Control Area.

Q. SINCE LOADS SERVED BY BEHIND-THE-METER GENERATING UNITS BOTH IMPACT ISO OPERATIONS AND BENEFIT FROM THE ISO'S RESONSIBILITIES AS CONTROL AREA OPERATOR, SHOULD THAT LOAD SHARE COST RESPONSIBILITY FOR THE ISO'S CONTROL AREA SERVICES?

A. Yes. As explained earlier, the ISO currently provides scheduling services for the Control Area and undertakes responsibility for system balancing and arranging adequate reserves (Ancillary Services) for all Loads within its Control Area, using the ISO Controlled Grid to accomplish these requirements. The ISO undertakes these responsibilities as Control Area operator. Load served by behind-the-meter Generation should bear its allocable portion of the costs the ISO incurs in providing its Control Area responsibilities. Failure to assess such costs to the Load "behind-the-meter" would improperly shift costs to other Loads within the Control Area.

II. CONTROL AREA SERVICES

Q. WHAT IS THE CONTROL AREA SERVICES CHARGE?

A. As defined in the proposed ISO Tariff language submitted in this filing, the Control Area Services Charge is the component of the Grid Management Charge that provides for recovery of the ISO's costs of ensuring safe, reliable operation of the transmission grid and dispatch of bulk power supplies in accordance with regional and national reliability standards, including, but not limited to:

- performing operation studies;
- system security analyses;
- transmission maintenance standards;
- system planning to ensure overall reliability;
- integration with other Control Areas;
- emergency management;
- outage coordination;
- transmission planning; and
- scheduling Generation, imports, exports, and Wheeling in the Day-Ahead and Hour-Ahead of actual operations.

Q. WHAT ENTITIES BENEFIT FROM OR RELY ON THESE SERVICES?

A. As I described above, <u>all</u> Market Participants, including behind-the-meter facility operators, either benefit from or rely on these services provided by the ISO. These services are fundamental to Control Area reliability and non-discriminatory open access to the ISO Controlled Grid. None of the above-listed items could be eliminated without harming Market Participants.

Q. WHAT IS INVOLVED IN PERFORMING OPERATION STUDIES AND SYSTEM SECURITY ANALYSES?

A. The operation of the power system is dynamic with respect to the balance of supply and demand and with respect to the configuration of the power system. Changing weather conditions have a significant effect on the demand for electricity within and beyond the ISO's Control Area boundaries. Planned and forced outages of major Generation and transmission facilities also affect the nature of power delivery. The relative locations of Generating Units and Loads must be considered in light of available transmission capacity (including with respect to planning for what is to happen when the next Generating Unit or transmission line is forced out of service). Operation studies rely on large databases and advanced computer applications to model and simulate the power system. Operations Engineers perform several types of studies with these databases and computer applications, including but not limited to steady-state power flow, transient stability, and post-transient stability. These studies are aimed at determining the performance and expected response of the system under normal and contingency conditions. Unlike grid planning studies, which evaluate the performance and response of the power system one or more years in advance, operation studies evaluate the expected performance and response of the power system in the nearer-term (*e.g.*, seasonal nomogram studies, or studies to determine minimum loading requirements for Reliability Must-Run Units, or studies supporting outage coordination). Like grid planning, however, many of these studies are coordinated with other transmission operators and neighboring Control Areas within the WSCC interconnection. Of chief concern in this study coordination effort is accuracy of the data used to model the system in each respective area in the interconnection. The results of many of these studies are reflected in updated, or new, operating procedures used by system operators to maintain the security and reliability of the interconnected power systems.

Q. HOW DOES THE PERFORMANCE OF OPERATION STUDIES AND SYSTEM SECURITY ANALYSES BENEFIT ALL MARKET PARTICIPANTS?

A. These studies are relied upon by system operators to not only maintain the reliability of the power system, but also to maximize its available uses. In the absence of performing such studies, the operational flexibility of the power system would be limited significantly. For example, available transmission capacity on major transmission interfaces would be reduced and minimum loading requirements for Reliability Must-Run Units would be increased in local areas that were known to have voltage, thermal or stability problems. That is, the operation of the power system would be based on worst-case scenarios and much more conservatively operated by ISO system operators, and therefore more costly for Market Participants because of restricted capabilities.

Q. WHAT ARE TRANSMISSION MAINTENANCE STANDARDS?

A. These are the ISO's standards of performance applicable to PTOs. The ISO maintenance standards are based on availability formula and relate to PTOs' maintenance, inspection, repair and replacement of transmission facilities that have been transferred to the Operational Control of the ISO (*i.e.*, the elements of the ISO Controlled Grid).

Q. HOW DO TRANSMISSION MAINTENANCE STANDARDS BENEFIT ALL MARKET PARTICIPANTS?

A. Lack of adequate transmission facility maintenance is a determining factor in the frequency and duration of outages. Therefore, the performance-based standards are aimed at increasing the availability of the ISO Controlled Grid for the benefit of Market Participants. Absent adequate standards for maintenance, service to Market Participants cannot be assured at any particular level of availability.

Q. PLEASE DESCRIBE WHAT IS MEANT BY THE INTEGRATION WITH OTHER CONTROL AREAS?

A. The ISO Control Area is an integral part of the WSCC interconnection, and must coordinate its planning and operations with all other Control Area operators throughout the interconnection to assure adequacy and reliability of power supply. That is, there must be a plan for ensuring overall reliability of the power systems comprising the WSCC interconnection. This coordination spans the range of planning and operating functions, from multi-year planning to real time responses to forced outages of generation and transmission facilities. Much of this coordination is accomplished through committees, work groups and task forces organized within the WSCC, and includes participation by representatives from a broad range of stakeholder groups. Other aspects of this coordination are accomplished through inter-Control Area communications that occur before, during and after each operating hour on a 24-hour, 7-day-per week basis. A large amount of information is shared among the WSCC Control Areas to integrate the operation of the WSCC interconnection reliably. The ISO's participation in these forums, and its real time coordination with other Control Areas, is critical to the safe and reliable operation of the WSCC interconnection. Because the ISO Control Area is interconnected with neighboring Control Areas, some of which are only a fraction of its size, its planning and operation can have measurable effects on the integrated power systems of the WSCC. As well, because of the ISO's large size relative to the interconnection, it can affect almost all integrated power systems of the interconnection. This promotes mutual interest in maintaining a high level of communication between systems. The ISO therefore has developed the resources necessary to accomplish this high degree of coordination and integration with other Control Areas.

Q. WHO RELIES UPON OR BENEFITS FROM THE ISO'S INTEGRATION WITH OTHER CONTROL AREAS?

A. All Market Participants generally rely upon and benefit from the ISO's integration with other Control Areas. In particular, all load-serving entities electrically connected to the power systems that comprise the ISO Control Area benefit and rely upon the ISO's integration with other Control Areas. At a minimum, such load serving entities have a real interest in such integration; if not to access alternative sources of economic supply, to at least maintain service continuity at rated voltages and frequency. More generally, the ISO Control Area spans most of the state of California, which traditionally has been a net importer of power. Without such integration, available supply would be limited severely with adverse effects on both interstate commerce and the continuity of service to electric customers that are not completely self-contained and isolated from the power systems comprising the ISO Control Area.

Q. WHAT IS EMERGENCY MANAGEMENT?

A. The ISO Control Area represents a large and geographically diverse region of the western United States in which there have been emergencies, ranging from natural disasters to electric power shortages, which jeopardized the continuity of electric service. As such, the ISO has developed and maintains an emergency response plan that includes coordination with local, state and federal agencies, in addition to coordination with PTOs and other grid operators. In the case of emergencies affecting the electric power systems within the ISO Control Area, the ISO manages the effects of the emergency and coordinates restoration efforts with the PTOs, other grid operators and government agencies. The ISO also coordinates training sessions and system operator drills with the PTOs, other grid operators and government agencies to maintain readiness.

Q. HOW DOES EMERGENCY MANAGEMENT BENEFIT ALL MARKET PARTICIPANTS?

A. The ISO is situated uniquely to monitor the combined power systems of the Control Areas formerly operated by PG&E, SCE and SDG&E and to evaluate the status of the electric system during emergencies. No one grid operator or government agency has the ability to monitor the scope of electric infrastructure within the combined Control Areas of PG&E, SCE and SDG&E as does the ISO. The ISO's management of emergency preparedness, response and restoration is aimed at containing, or minimizing, the adverse affects of man-made or natural disasters on electric supply and demand. Its goals include the protection of life and property, communication of known scope and expected duration of events, and the restoration of electric service to the extent disrupted.

Q. WHAT IS OUTAGE COORDINATION?

A. As mentioned previously with regard to operation studies and security analysis, planned and forced outages of major generation and transmission facilities affect the nature of power delivery. Moreover, the relative locations of Generating Units and loads must be considered in light of available transmission capacity. The ISO coordinates planned outages of transmission facilities and Generating Units. For all of the transmission facilities comprising the ISO Controlled Grid, the ISO works with PTOs to coordinate planned outages on an annual basis. Similarly, the ISO coordinates the outage requests submitted by owners of Reliability Must-Run Units on an annual basis. The plans are updated (quarterly), as required, throughout the year to accommodate the maintenance plans of PTOs and owners of Reliability Must-Run Units to the greatest extent possible. The ISO's outage coordinators are assisted by operations engineers in evaluating the individual and combined effects of various outages occurring in various seasons of the year. The ISO evaluates and manages over 25,000 outages throughout the course of each year.

Q. HOW DO ALL MARKET PARTICIPANTS BENEFIT FROM OUTAGE COORDINATION?

A. Absent the ISO's coordination of planned outages of Reliability Must-Run Units and the ISO Controlled Grid, there would be no assurance that the power system as a whole, or portions thereof, would be operated within prevailing limits and ratings.

Q. WHAT IS INVOLVED IN TRANSMISSION PLANNING?

A. The ISO reviews each PTO's bulk power program (a five-year program filed with the ISO every year) and reviews the studies the PTOs perform for connecting new Generating Units and loads to the ISO Controlled Grid. In addition, since the PTO studies are focused mainly on their own systems, the ISO conducts an independent review of the ISO Control Area to determine that there are no reliability criteria violations. The ISO's recommendations, if any, are either implemented by the PTOs or the problem is resolved via dispute resolution processes. The ISO performs studies to determine Reliability Must-Run Contract requirements and dual fuel Generating Unit requirements. The ISO was instrumental in the preparation of the new ISO Reliability Criteria, and is working with PTOs toward the establishment of common facility ratings when feasible. Additionally, the ISO leads or supports several regional and national technical and engineering groups within the WSCC, the two Regional Transmission

Associations (SWRTA and WRTA), the Western Interconnection Coordination Forum and the NERC dealing with transmission planning coordination and the creation of new regional and national transmission planning standards.

Q. HOW DO ALL MARKET PARTICIPANTS BENEFIT FROM TRANSMISSION PLANNING?

A. Market Participants benefit from transmission planning in several ways. First, by leading and participating in several planning forums, the ISO assures that the market rules are taken into consideration whenever new standards or procedures are put in place. Second, by working with the PTOs and the regulatory agencies, the ISO works toward expansion of the grid to enhance reliability, minimize congestion, and assure compliance with Applicable Reliability Criteria. Third, by determining the minimum amount of RMR contracts, the ISO is better able to minimize the costs required to maintain the reliability of the ISO Controlled Grid.

Q. WHAT IS INVOLVED IN SCHEDULING GENERATION, IMPORTS, EXPORTS, AND WHEELING IN THE DAY-AHEAD AND HOUR-AHEAD OF ACTUAL OPERATIONS?

A. Scheduling Coordinators submit Balanced Schedules within the Day-Ahead and Hour-Ahead scheduling processes, with the exception of some scheduled uses of Existing Contract rights that provide for flexibility beyond the Day-Ahead and Hour-Ahead processes. Besides Energy scheduled for Generating Units, Loads, trades with other Scheduling Coordinators, and with other Control Areas (interchange into, out of, or through the ISO Controlled Grid), these Balanced Schedules can also include a Scheduling Coordinator's bids into the ISO's auctions for Ancillary Services, its self-provided schedules of Ancillary Services or its trades of Ancillary Service obligations with other Scheduling Coordinators. As well, these Balanced Schedules may also include Adjustment Bids that can be used by the ISO in its Congestion Management processes. The ISO evaluates all of the submitted schedules and makes adjustments, as required, to satisfy Reliability Criteria (*e.g.*, to ensure that transmission paths are not scheduled beyond their flow limits). The Day-Ahead process includes a second Congestion Management iteration to allow Scheduling Coordinators the ability to self-manage their schedules and to limit or avoid paying Usage Charges.

The ISO's interchange schedulers coordinate with eleven (11) adjacent Control Areas to validate all interchange schedules (whether new firm uses of ISO transmission service or uses of Existing Contract rights) submitted by Scheduling Coordinators for each hour of the Trading Day. Interchange arranged by the ISO with other Control Areas on behalf of all Scheduling Coordinators must be consistent with WSCC scheduling practices and NERC policies. Similarly, operations personnel must assure that adequate amounts of Ancillary Services are available as self-provided or procured, and that no transmission path is overscheduled, to meet WSCC criteria and NERC policies for the actual hour of operation. Changes in system conditions after the close of the Day-Ahead or Hour-Ahead processes can result in changes to Ancillary Service requirements or available transmission capacity (*e.g.*, a transmission path is derated). After the close of the Day-Ahead process, these changes can sometimes be accommodated in the Hour-Ahead process (*e.g.*, time permitting, resources available, etc.). After the close of the Hour-Ahead process, however, any and all changes must be accommodated prior to and during the actual operating hour (*i.e.*, during real time).

Under the ISO's proposed unbundling of the GMC, Scheduling Coordinators can limit their allocated shares of GMC charges attributable to Inter-Zonal Scheduling or Market Operations to the extent they self-manage their Energy schedules to avoid incurring Usage Charges (associated with Congestion Management), self-provide their Ancillary Service obligations, and do not vary from their Final Hour-Ahead Schedules (*i.e.*, the metered quantities for resources are equal to the Final Hour-Ahead Schedules). Additionally, Usage Charges can be avoided by Scheduling Coordinators that schedule the use of their Existing Contract rights.

Q. HOW DO THESE ACTIVITIES BENEFIT ALL MARKET PARTICIPANTS?

A. Operations personnel review the Day-Ahead and Hour-Ahead schedules of Generation, Demand and Control Area interchange to prepare for each hour of operation. Since Scheduling Coordinators have the flexibility to choose to schedule their resources in either the Day-Ahead or Hour-Ahead markets, or to rely on the ISO's Imbalance Energy market, control room personnel must scrutinize the results of Day-Ahead and Hour-Ahead processes to assure that adequate resources are available to meet the forecasted Demand, within the capabilities of the power system, in accordance with WSCC criteria and NERC policies. That is, irrespective of a Scheduling Coordinator's participation in Inter-

Zonal Scheduling or Market Operations, a Scheduling Coordinator relies on the ISO for the fundamental aspects of Energy accounting, coordination, and monitoring services that are necessary to accommodate the Scheduling Coordinator's operation of its resources reliably.

Q. THANK YOU, MR. CARLSON. I HAVE NO FURTHER QUESTIONS.