UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Turlock Irrigation District and	**)**	
Modesto Irrigation District	**)**	
	)	
v.	**)**	**Docket No. EL99-93-000**
	)	
California Independent System	**)**	
Operator Corporation	**)**	

Affidavit of
Trent A. Carlson
On behalf of
The California Independent System Operator Corporation

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

Qualifications

2. 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. I have testified as an expert witness in Superior Courts of the County of San Francisco and the County of Los Angeles. I have also testified as an expert witness before the Hawaii Public Utilities Commission.

3. 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 and economists focused on system studies, strategic planning assignments, power marketing assessments, contract negotiations, and providing expert witness services. Assignments included the development of the Philippine's first open access transmission tariff; preparation of power supply 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 assignment of transmission entitlements.

4. Since joining the ISO, initially as an Interim Staff contractor, I have been assigned to the Scheduling Applications ("SA") development team, working on the preparation of functional descriptions for the Detailed Statements of Work, review of 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 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 ISO's Operations and Engineering Department in September of 1997. Prior to assuming my current position as the Director of Operations Support and Training Department ("OSAT"), I was the Senior Engineer in the Grid Operations Department. The OSAT Department develops and maintains all Operating Procedures, provides dispatch support to control room operators, coordinates electrical emergency response efforts, administers the Master Training Program, and manages the RD&D efforts of the ISO related to advancing the market front-end approach to grid operations of the ISO Control Area.

5. I provide this affidavit to respond to certain claims made in the September 17, 1999 Complaint of the Turlock Irrigation District and the Modesto Irrigation District ("Complaint") and in the accompanying affidavit of Mr. Paul G. Scheuerman.

6. To summarize the conclusions that I have reached, which are discussed further in the numbered paragraphs below:

(a) The contention that the provisions of the ISO Tariff erect barriers that effectively preclude irrigation districts and other municipal utilities within the ISO's Control Area from participating in the ISO's Ancillary Services, Congestion Management and Imbalance Energy markets are unfounded. Resources owned by municipal utilities in California can *and do* participate in those markets on a basis that preserves their rights under pre-ISO transmission service agreements and their ability to operate their utility systems.

(b) The requirements imposed by the ISO Tariff on generators and loads within the ISO's Control Area that participate in the markets administered by the ISO are necessary for the ISO to preserve reliability and to meet the ISO's responsibilities as the Control Area operator.

(c) The ISO, as a Control Area operator, is required to secure the required amounts of Ancillary Services to satisfy WSCC criteria and NERC standards. The ISO's load responsibility establishes the ISO's Ancillary Services requirements. Without accurate estimates of generation, load, and interchange, the ISO's Control Area responsibilities are compromised; as is the reliability of the Control Area and interconnection.

(d) The Districts do not operate their own Control Areas. The ISO, not the Districts, is responsible for Control Area-specific functions. These functional requirements derive from the standards and criteria established by the NERC and WSCC, and go far beyond providing, or contracting for the provision of, energy and capacity as a vertically integrated company.

(e) The Districts have argued that none of their internal generation uses the ISO Controlled Grid. This is not the case, just as it is not the case that electricity follows the contract path. Instead, those systems operating within a Control Area are inextricably and synchronously integrated with one another. In fact, the ISO Controlled Grid is relied upon for incremental energy in the event of a disturbance (e.g., loss of generation).

(f) There is nothing in the ISO Tariff that would preclude or limit the Districts' ability, either together or separately, to create a new Control Area. It is the NERC and WSCC that set and apply the relevant standards.

7. The Complaint and Mr. Scheuerman's affidavit contend that the provisions of the ISO Tariff effectively preclude the Districts from participating in the ISO's markets for Ancillary Service capacity and Imbalance Energy. These claims are without basis. Publicly-owned generating units located within the ISO Control Area can *and do* participate in ISO markets. The ISO Tariff provides a number of mechanisms available to Generators, including generating units owned by municipal utilities, for this purpose.

As I will explain, other municipal utilities are currently using these existing mechanisms to participate in the ISO's markets.

8. The owner of any Generating Unit located within the ISO's Control Area that desires to participate in the ISO's markets must execute a Participating Generator Agreement ("PGA"). This agreement essentially requires the Generator to abide by the applicable terms of the ISO Tariff and commits the ISO to deal with the Generator in accordance with the ISO Tariff. Once a Generator has executed such an agreement and it has been filed with the FERC, the Generator may, through a Scheduling Coordinator, submit bids to sell Ancillary Service capacity and/or Imbalance Energy through the ISO's markets.

9. A municipal utility can execute a PGA with respect to its generating units located within the ISO Control Area, for the purpose of selling excess capacity and energy through the ISO's markets. The municipal utility need not also rely on the ISO's markets to meet its own needs for serving its customers (although, as I will explain, it may do so). If a municipal utility chooses to participate in the ISO's markets on this basis, its sales of Ancillary Services and/or Imbalance Energy will not cause it to incur any of the costs that, under the ISO Tariff, are allocated on the basis of Demand served by a Scheduling Coordinator.

10. The ISO Tariff generally requires each Generating Unit within the ISO's Control Area that is participating in the ISO's markets through a PGA to be metered individually and to respond to dispatch instructions on that basis. As I will explain in greater detail below, this requirement is necessary for

the ISO to fulfill its responsibilities as the Control Area operator. The ISO Tariff also permits Generating Units that meet the definition of “Physical Scheduling Plants” to combine their operations.

11. The execution of a PGA does not equate to the loss of control jeopardizing the ability of a publicly owned system to operate as a vertically integrated, or full-service utility, provider.

(a) There are several publicly owned systems that have already successfully made arrangements to become certified as Scheduling Coordinators and that have, in varying degrees, been participating in the ISO's markets. Additionally, some have either executed, or are in the process of executing, PGAs. These Scheduling Coordinators include, but are not limited to, the following:

(i) City of Anaheim, ANHM, certified
(ii) City of Azusa, AZUA, certified
(iii) City of Banning, BAN1, certified
(iv) City of Pasadena, PASA, certified
(v) Modesto Irrigation District, MID1, certified
(vi) City of Riverside, RVSD, certified
(vii) City of Vernon, VERN, certified

(b) The execution of a PGA does not void the Tariff provisions that are intended to honor Existing Contracts. For example, signing a PGA does not subject the scheduled uses of an Existing Contract to Usage Charges under the ISO's Congestion Management protocols.

- The ISO Tariff contains two sections (*see*, ISO Tariff sections 2.4.3 and 2.4.4, and related subsections) as well as several protocols (*see, e.g.*, the Schedules and Bids Protocol, the Scheduling Protocol and the Dispatch Protocol) that address Existing Contracts. As one of many examples, the ISO's Congestion Management protocols give explicit recognition to the priority of Existing Contracts (*see* ISO Tariff section 7 and the Schedules and Bids Protocol section 4.6 in the definition of Adjustment Bids and scheduling system functionality).

- The ISO Tariff also recognizes that the rights and obligations of parties to Existing Contracts are complicated, and that they vary from one Existing Contract to another. Additionally, the Tariff recognizes that the ISO's requirements can be different than those set forth in Existing Contracts. The Tariff, therefore, provides that the ISO will provide information regarding the basis of its calculations to the Existing Contracts parties to settle any differences bilaterally (*see*, for example, section 2.4.4.4.4.5).

(c) The ISO markets have been designed to give greater, rather than less, flexibility in several respects. For example, the ISO does not impose financial penalties for deviating beyond narrow bandwidths of scheduled load and generation. Instead, the ISO provides market participants the opportunity to take advantage of, as well as to risk, the real-time Imbalance Energy markets and the financial settlements thereof. Nor has the ISO limited or excluded publicly-owned utility participation in new firm uses of ISO transmission service. Indeed, the ISO not only allows publicly-owned utilities to compete for new firm uses of ISO transmission service, but also provides for their scheduled uses of reserved transmission capacity under Existing Contracts.

(d) The execution of a PGA does not require that all of the municipal utility's Generators be represented by the same Scheduling Coordinator. Instead, the ISO only requires that each meter be represented by no more than one Scheduling Coordinator. In addition, the municipal utility has the same opportunity to exercise the Physical Scheduling Plant provisions of the Tariff as does any other market participant. That is, the municipal utility may aggregate several individual Generating Units into a single Physical Scheduling Plant in accordance with the Tariff.

(e) The Tariff allows Scheduling Coordinators to schedule and meter Demand in one of three different ways: by demand zone, load group, or individual take-out point. The execution of a PGA has no effect on this choice, which can be made by any Market Participant's Scheduling Coordinator.

12. It is only during those instances when the ISO, as Control Area operator, is required to take action to avoid or cure an operating emergency that a Participating Generator may be called on to adjust the output of a

resource to something other than what was offered by the relevant Scheduling Coordinator.

13. The execution of a PGA does not require a municipal utility (or any other market participant for that matter) to bid the resource into any one or a number of the ISO's markets for Ancillary Services, transmission capacity or real-time Imbalance Energy. Scheduling Coordinators are free to bid these resources as they wish.

14. The ISO must have control of the resources that are relied upon to meet Control Area responsibilities.

    (a) The ISO, as a Control Area Operator, is required to secure the required amounts of Ancillary Services to satisfy WSCC criteria and NERC standards. The WSCC defines a Control Area as: "An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, <u>capable of controlling generation</u> to <u>maintain its interchange</u> schedule <u>with other control areas</u>, and <u>contributing to frequency regulation</u> of the interconnection." *WSCC Minimum Operating Reliability Criteria*, March 1999 [emphasis added].

    (b) The ISO's load responsibility establishes the ISO's Ancillary Services requirements. The WSCC defines load responsibility as: "A <u>control area's</u> firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier." *WSCC Minimum Operating Reliability Criteria*, March 1999 [emphasis added]. Without accurate estimates of generation, load, and interchange, the ISO's Control Area responsibilities are compromised; as is the reliability of the Control Area and interconnection.

(c) Each Control Area in the WSCC has its own load responsibility and is required to satisfy the Minimum Operating Reliability Criteria by arranging for the adequate supply of Regulation, reserves and other reliability services. The ISO is not excused from any part of these obligations and responsibilities. Nor is the ISO in a position to relinquish any part thereof. Each Control Area must satisfy its own load responsibility by arranging for the requisite kinds, types and amounts of reliability services. Each Control Area operator within the interconnection has the responsibility to make the reliability services associated with its load responsibility available on a continuous basis.

(d) In the ISO, Ancillary Services are obtained from several types of suppliers: Generators, Loads and interties. The ISO will accept offers of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve from Generators within the ISO Control Area. Non-Spinning Reserve and Replacement Reserve may be offered by Loads inside the ISO Control Area. The ISO also accepts offers of Spinning Reserve, Non-Spinning Reserve and Replacement Reserve from resources located outside of the ISO Control Area at points of interchange with other Control Areas (*i.e.*, System Resources). As well, the Tariff provides for Scheduling Coordinator offers of Regulation, Spinning Reserve, Non-Spinning

Reserve and Replacement Reserve from resources located inside the ISO Control Area and within a Metered Subsystem (*i.e.*, System Units).

(e) Both System Resources and System Units are still under development at the ISO. For example, the ISO does not yet accept offers of Regulation from System Resources. With regard to System Units, none have been established yet. However, as the Commission is aware, the ISO has been working within the Existing Rights Working Group ("ERWG") to define a System Unit that meets the needs of both the ISO and Metered Subsystem owners (*see* Affidavit of Michael Dozier for a description of the ISO's efforts in this regard). Until such time as System Units are so defined, there is nothing in the Tariff that precludes the Districts from executing a PGA for one or a number of their Generating Units and participating in the ISO's markets in accordance with the Tariff.

(f) For each Ancillary Service, Scheduling Coordinators can bid a zero price (including self-provision) or a non-zero price to supply Ancillary Services capacity. In either case, an energy bid associated with the reserved capacity must also be provided by the Scheduling Coordinator so as to be called upon, as necessary and in price merit order, by the ISO, in real-time, to maintain System Reliability in accordance with Control Area requirements.

(g) For those resources located outside of the Control Area, Scheduling Coordinators have the additional burden of arranging interchange schedules with their host utility and the ISO. As with all interchange schedules, this is required so that each Control Area can assure that it is meeting its Control Area requirements and that the proper arrangements have been made with respect to transmission (*e.g.*, in the case of delivering Ancillary Services, the transmission must be firm). With respect to Ancillary Services, this represents another burden associated with System Resources. Suppliers of Ancillary Services from System Resources are required to certify to the ISO "…their ability to deliver the service to the point of interchange with the ISO Control Area (including with respect to their ability to make changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO)." Tariff section 2.5.7.4.2. Without such certification, System Resources are ineligible to supply Ancillary Services to the ISO. Generators within the ISO Control Area, whether represented by individual Generating Units, Physical Scheduling Plants or, in the future, System Units, are not certified in this manner since they are subsumed within the ISO and the ISO is responsible for them as the Control Area operator in accordance with its Tariff that incorporates WSCC criteria and NERC standards. The ISO certifies these internal resources on a basis reflecting the fact it is able to call on the capacity held in reserve at any time during the hour without having to coordinate such actions with one or a number of other Control Area operators. These distinctions, and others, between the supply of Ancillary Services from suppliers of resources located within and from outside the ISO Control Area have already been shared with the participants in the ERWG, in part by means of the distribution of a partial listing of those distinctions to all participants in the ERWG (including representatives of the Districts) and discussion of those distinctions with the ERWG on September 11, 1998. *See* Exhibit 1 to this affidavit. These distinctions include: (1) real time deviations by resources located inside the ISO's Control area (System Units) contribute to Control Area Area Control Error ("ACE") while similar deviations by resources outside the control area do not; (2) System Resources are Scheduled as Control Area Interchange while System Units are not; (3) resources located outside of the ISO Control Area are under the jurisdiction of another Control Area operator; and (4) the ISO is responsible for the real-time balance of loads and resources within the ISO Control Area. The Districts have argued that a System Unit (*i.e.*, a group of resources located within a Metered Subsystem inside the ISO Control Area) should be treated similarly to a System Resource located outside of the ISO Control Area. For this to be the case, the Districts would have to operate their own Control Areas and take on the responsibilities and obligations of a Control Area operator.

15. The Districts do not operate their own Control Areas. The ISO, not the Districts, is responsible for Control Area-specific functions. These functional requirements derive from the standards and criteria established by the NERC and WSCC, and go far beyond providing, or contracting for the provision of, energy and capacity as a vertically integrated company.

Indeed, the obligations and responsibilities of a Control Area operator include, but are not limited to, the following:

- Frequency control (continuous balancing of Control Area load, generation and interchange) and time-error correction;
- Managing and eliminating Operational Transfer Capability violations (and reporting OTC violations to the WSCC);
- Maintaining an adequate supply of Operating Reserves (and reporting OR violations to the WSCC);
- Minimizing Area Control Error (and reporting CPS1 and CPS2 results to the WSCC);
- Managing loop-flow;
- Managing inadvertent interchange (and reporting status to the WSCC); and
- Meeting WSCC criteria and NERC standards (including the responsibilities associated with WSCC RMS reporting and NERC Standard Compliance reporting).

(a) Additionally, as of September 1, 1999, the WSCC Reliability Management System ("RMS") Phase I system of monetary penalties and sanctions is now in full force and effect. These monetary fines are the responsibility of the ISO as Control Area operator. It has, therefore, become all the more critical for the ISO 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.

(b) Moreover, this new regime of NERC and WSCC penalties and sanctions will make it all the more critical to have accurate information on the schedules, status and operation of resources within the Control Area. Without such information, the allocation of any such penalties and sanctions will be imprecise.

(c) With or without the NERC and WSCC penalties and sanctions, the need for accurate information on the schedules, status and operation of resources within the Control Area is clear. To illustrate the point, consider the fact that Control Area load, in real-time, is calculated as the difference between generation and net interchange (*i.e.*, Load = Generation - Net Interchange, with exports being positive). The extent to which generator output is <u>not</u> monitored by the Control Area Energy Management System is the extent to which Control Area load is underestimated. The extent to which load is underestimated is the extent to which Ancillary Services are insufficiently provided to cover total load responsibility. The same is true with respect to scheduling. In this regard, the ISO has recently added a safeguarding market mechanism that will allocate the cost of deviation Replacement Reserves to those that choose not to schedule a portion of their resources in either the Day-Ahead or Hour-Ahead processes. Similarly, the extent to which resources are <u>not</u> metered is the extent to which the allocation of Replacement Reserve costs will be shifted to other market participants. This result is of particular significance now that the ISO bills market participants for Ancillary Services based on metered demand.

(d) The Districts have argued that none of their internal generation uses the ISO Controlled Grid. This is not the case, just as it is not the case that electricity follows the contract path. Instead, those systems operating within a Control Area are inextricably and synchronously integrated with one another. Irrespective of the fact that some systems have not transferred Operational Control of their transmission facilities to the ISO, the transmission facilities are, nonetheless, located within the metered boundaries of the Control Area operated by the ISO. For example, assume one of the Districts is generating 120 MW of electricity, none of which "uses" the ISO Controlled Grid. Assume also that an unexpected event occurs and the District's 120 MW of generation is disconnected from the system. The ISO's 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 Energy Management System ("EMS"), Participating Generators providing Regulation (*i.e.*, enabled Automatic Generation Control) would be issued control signals to adjust their output for the 120 MW deficiency. To return the Regulation units back 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 District had its generation monitored by the ISO's EMS, the ISO would have also detected the cause of the ACE excursion. On the other hand, if the District did <u>not</u> have its generation being monitored by the ISO EMS, the disconnection of the generation would have still 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 District's operators get the information to the ISO Control Area operators). This is one of many examples that can be cited to disprove the notion that a contract can somehow redirect the flow of power, or confound the laws of physics, in a Control Area comprised of electrically interconnected, alternating current, transmission facilities.

16. The Districts are free, if they want, to establish their own Control Areas, assume the concomitant responsibilities, and have their generation and load treated as System Resources.

(a) There is nothing in the ISO Tariff that would preclude or limit the Districts' ability, either together or separately, to create a new Control Area. It is the NERC and WSCC that set and apply the relevant standards.

(b) For many years, the Sacramento Municipal Utility District ("SMUD") has considered the possibility of operating as a Control Area, but has not. Pasadena, on the other hand, had operated as a separate Control Area for many years, until July 22, 1999, when it de-certified its separate Control Area and became part of the ISO Control Area. Now, Pasadena's loads and resources are operated as an integral part of the ISO Control Area. Rather than bidding as a System Resource, as it had previously done as a separate Control Area, Pasadena has executed a PGA for its Generating

Units and is bidding in the ISO's markets from those units – in just the same manner as is and has been available to the Districts. Moreover, the ISO has made arrangements with Pasadena to continue to accommodate the municipality's Existing Contracts even while Pasadena participates in the ISO' s markets.