WESTERN AREA POWER ADMINISTRATION

SIERRA NEVADA REGION

Public Information Forum

Post-2004 Operational Alternatives

At this time Tom Carter, Power Operations Manager for Western's Sierra Nevada Region, will present the operational alternatives under consideration.

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<u>Operational Alternatives</u>

Good morning. My intent this morning is to describe why Western is considering operational alternatives for the post-2004 period, describe the alternatives that are under consideration, outline the factors that Western will consider, among others, to make a decision on which alternative to implement, and then describe some of the pros and cons associated with each alternative.

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Why?

The Sierra Nevada Region has three long-term contracts expiring on December 31, 2004. The first is the contract for interconnection of the Malin-Round Mountain 500-kV transmission line at Round Mountain Substation between Western and the Pacific Gas & Electric Company, or PG&E, Contract -2949A.

The second is the contract among Western and the California Pool Companies, PG&E, Southern California Edison Company, and San Diego Gas and Electric Company, for transmission and exchange service, Contract -2947A. The third is Contract -2948A between Western and PG&E that essentially integrates the operation of the federal system with the system of PG&E, and provides, among other things, for PG&E to provide control area services to Western and transmission service for federal power to Western's customers connected to the PG&E system. PG&E has stated that they do not intend to extend Contracts 2947A or 2948A, but are interested in a new interconnection arrangement at Round Mountain Substation. Western has begun discussions with PG&E for such an agreement.

Contract -2948A defined the operational relationship between PG&E and Western for the past 40 plus years. In essence, Western's system was integrated with the PG&E system, federal power was combined with PG&E's energy resource portfolio, and an amount of power equal to the federal allocations was delivered over the PG&E and Western's system to our customers, both those directly connected and those not directly connected to the Western system. PG&E also provided firming energy to support the federal power allocations, and provided control area services to Western. With the relationship under Contract -2948A ending, Western must determine the best way to obtain the control area services that have been provided by PG&E in the past.

California restructured its electric utility industry in 1996 with the passage of Assembly Bill 1890 and created the California Independent System Operator, or ISO. The ISO took over operational control of the transmission lines of the three investor-owned utilities and became the control area operator of the geographic service territory previously served by the three utilities in the spring of 1998.

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The ISO presently provides control area services to PG&E for contract 2948A deliveries. Western must select an operational scheme in preparation for January 2005. The operational alternatives under consideration will result in Western either obtaining or self-providing the control area services that have previously been provided by PG&E and the ISO under Contract -2948A.

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The Alternatives

Western has identified the following three alternatives:

1. Become a Participating Transmission Owner, or PTO, with the ISO;
2. Become a sub-control area within the ISO control area similar to the Metered Subsystem model;
3. Form a new control area certified by the Western Electricity Coordinating Council, or WECC, and the North American Electric Reliability Council, or NERC.

These alternatives are not mutually exclusive and, as part of this public process, if other alternatives are identified, Western is willing to consider them.

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PTO Alternative

Under this alternative, the Sierra Nevada Region, or SNR, would execute a Transmission Control Agreement with the ISO. This agreement would transfer dispatch direction for the Federal transmission system and all transmission entitlements to the ISO, but SNR would retain the responsibility to operate and maintain the Federal system. Execution of the agreement would obligate SNR to conform its maintenance, operations, business, and administrative practices to all applicable ISO protocols and procedures. In order to select this alternative, these protocols and procedures, and the terms of the agreement, will have to be examined closely to be sure that they are not inconsistent with federal law.

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In order to implement this alternative, Western and Reclamation will also have to execute a Participating Generator Agreement with the ISO. This agreement would transfer operational control of the Central Valley Project, or CVP generation to the ISO, but Reclamation would retain the responsibility to operate and maintain the Federal generation. Execution of the agreement would also obligate Reclamation to conform its maintenance, operations, business, and administrative practices to all applicable ISO protocols and procedures. Execution of this agreement will allow SNR to contribute energy and/or ancillary services in the ISO markets that is in excess of contractual obligations of SNR, if available. To implement this alternative, Reclamation and SNR will have to examine the terms of the agreement and the protocols and procedures to be sure that they are not inconsistent with federal law.

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Under this alternative, scheduling of power across the Federal transmission system would be done by the ISO under provisions of the ISO tariffs. Under terms of the current tariffs, transmission of CVP generation to project use loads and SNR's customers will not be afforded any preference. Any congestion that occurs will be dealt with by the ISO by re-dispatching other resources.

Assuming that SNR is the Scheduling Coordinator, or SC, for CVP generation and project use loads, SNR will be required to pay congestion costs, and any imbalance costs that may occur with respect to the generation and project use loads.

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Implementation of this alternative would require that CVP generation be scheduled into the ISO control area for delivery to project use loads and SNR's customers. Any excess generation would be available to the ISO markets. Conversely, if generation was not sufficient to cover the scheduled deliveries to project use loads and SNR's customers, SNR and the SC's for SNR's customers would pay for the deficient amount at the market clearing price for energy imbalances unless subsequent purchases were made to hedge and avoid ISO real-time charges.

In essence, the costs associated with energy deliveries would be subject to the hourly ISO market prices, transmission congestion charges, imbalance energy charges, and all other charges that the ISO imposes to cover its costs or to collect revenue it must collect for the transmission owners, generators, and to cover control area operation expense. These charges would apply to all of SNR's customers, whether they were directly connected to the federal system or not.

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From an organizational perspective, this alternative appears to be the easiest to implement. SNR would not need a real-time transmission scheduling or an automatic generation control, or AGC, desk. However, to retain SNR's status as an SC, a 24-hour merchant desk would still need to be established. Also, a real-time transmission switching desk to monitor the federal system, perform outage coordination and switching will be needed. SNR would also have to maintain a settlements organization to account for and bill various charges from the ISO and to reconcile and account for revenues associated with generation sales into the ISO markets. Under this alternative, some of the organizational positions that might be saved by eliminating the real-time transmission scheduling and AGC desk may have to be used in the settlement function due to the numbers and complexity of the charges and accounting under the ISO tariffs.

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Sub-control Area Using the Metered Subsystem Concept

In lieu of becoming a Participating Transmission Owner, the ISO has offered SNR the option of becoming a Metered Subsystem, or MSS. In order to implement this alternative SNR and Reclamation will have to define the physical boundaries of the MSS and ensure that the appropriate revenue quality meters are present at each boundary and generator, and that appropriate communications and telemetry are in place. An option that the ISO has offered is that SNR can aggregate those customers that would like to be included in the MSS in a similar fashion as the MSS Aggregator Agreement the ISO has with the Northern California Power Agency. Since the MSS concept recognizes internal generation, Reclamation and SNR will not need to execute a Participating Generator Agreement.

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The key principles of the MSS arrangement given to SNR in a letter dated April 8, 2003, were included in the Federal Register Notice announcing this meeting and are:

1. The MSS methodology would model SNR's service territory to include the entities directly connected to its transmission system unless these entities did not want to be included for scheduling and settlement purposes. The California-Oregon Transmission Project or COTP line would also be included in SNR's MSS.
2. The ISO would provide "net" settlements treatment for various ISO market charges, as appropriate, based on cost causation principles.
3. No PG&E Unaccounted For Energy, or UFE, charge would be applied to load within SNR's metered subsystem.
4. SNR has the option of choosing to follow MSS load with MSS generation to minimize uninstructed energy deviation costs. Penalties would apply to all uninstructed deviations.
5. SNR and Reclamation would have the ability to schedule customized combinations of MSS resources on a System Unit basis to provide Reclamation with flexibility in dispatching individual generating resources.
6. Reclamation would not have to execute a Participating Generator Agreement and Reclamation and SNR would have full access to all ISO markets and associated services.
7. SNR would have the option of using multiple individual scheduling identifiers, as required, to facilitate and simplify ISO settlements for

SNR SC customers located on the ISO grid but which are external to, and scheduled separately from, the Western MSS.

8. Ancillary service obligations would be based on a load ratio share of the ISO ancillary services requirement.

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In order to minimize the cost of services provided by the ISO, SNR will need to provide balancing energy and assure that adequate reserves are self-provided for the entities included within the MSS. This will require a 24-hour per day AGC desk. It will also require revenue quality metering to be installed at the ISO boundaries with each of the MSS members' systems to accurately measure the net interchange to those systems from the ISO control area so that CVP generation can regulate for deviations in net interchange occurring at the aggregate of the MSS ties with the ISO. If the MSS alternative were chosen, SNR would calculate these deviations based on data updated every four seconds. The AGC package resident within the Supervisory Control and Data Acquisition System will be used to calculate the deviations and transmit the request for changes in generation to Reclamation.

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Under the MSS concept, all of the customers that chose to participate in the MSS would, as of the first day of operation, be provided regulation service by SNR for their deviations from scheduled interchange, within the limitations of the CVP generation to provide such service. Those entities directly connected to the SNR transmission system would also avoid certain of the ISO charges because deliveries of their allocations would not use the ISO grid, and the cost causation principles noted in the second of the ISO's key principles would appear to apply.

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Control Area Alternative

The control area alternative will require SNR to apply to NERC and the WECC to become a certified control area. SNR will have to assure these bodies that it can meet all of the NERC and WECC planning and operational standards and requirements. Key principles of the control area alternative were published in the Federal Register Notice that announced this meeting. They are:

1. The proposed control area boundaries will encompass those entities that are directly connected to the SNR transmission system, unless these entities do not want to be included. For those entities not wanting to be included in the control area, Western will work with these entities to dynamically schedule their loads into the control area of their choice. Currently, the loads and generation expected to be in the control area are the cities of Redding, Roseville, and Shasta Lake, the Lawrence Livermore National Laboratory, Reclamation's Tracy Pumping Plant, the Sutter Energy Center, Reclamations direct connected CVP powerplants, the East Contra Costa Irrigation District, and the Contra Costa Water District. Scheduling arrangements for off system generation and transmission at New Melones and San Luis will continue under the current contracts with PG&E, unless other arrangements are made.
2. Customers located within the control area will receive their allocation through internal schedules and will not experience any of the ISO

charges associated with those deliveries. Customers located on the ISO grid will be assessed charges for delivery of their allocations associated with the use of the ISO grid, ancillary service charges, transmission and distribution charges, and other ISO charges.

3. No PG&E UFE charges will apply to deliveries of federal power to entities within the control area.
4. SNR will follow the load for entities located within the control area. After experience is gained with control area operation, SNR will approach the ISO to dynamically schedule to its customers located in the ISO control area that wish to be included in the SNR control area. These off-system entities should then experience minimum imbalance energy charges from the ISO, but will be charged by SNR for SNR to provide regulation.
5. Reclamation will have the flexibility to move water releases around their system as needed and will provide the generation levels scheduled for delivery internal to the control area and to the ISO control area based on pre-schedules. There will be no uninstructed deviation charges associated with the control area alternative.

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6. SNR expects to be the SC for Reclamation generation and for the loads of some of its customers and, therefore, would still participate in the ISO markets under the control area alternative.
7. Schedules to customers located in the ISO control area will be performed as SC to SC trades no differently than many of the deliveries of federal power are made today.

8. SNR's reserve obligations will be shared by entities directly connected to the federal transmission system in proportion to the load of each of these entities within the control area. This is the same approach, a load ratio share, as proposed by the ISO in the MSS alternative. Regulation will be provided to the control area by CVP generation with the energy to be returned by those receiving such services.
9. All of the control area services outlined by the ISO in the MSS alternative proposal will be provided by SNR under the control area alternative to entities within the control area.

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Under this alternative, SNR would establish boundary and interface points with neighboring control areas. These would be the control areas of the ISO, Bonneville Power Administration, Sacramento Municipal Utility District, and other entities that establish a control area and are directly connected to the SNR transmission system. The appropriate metering and telemetry systems will be installed to accurately measure the interchange with these entities so that the actual net interchange of the control area can be calculated. SNR's Federal control area will be responsible, as other Western control areas are, to match load with generation and net imports, to provide assistance to regulate the frequency of the interconnected power system, and to carry adequate reserves to cover the largest hazard. The control area alternative will require SNR to maintain a 24-hour AGC desk and merchant desk identified under the MSS alternative described previously. Even though the Malin-Round Mountain line and the COTP line are expected to be included in the control area, SNR proposes that the path operator for the three-line California-Oregon

Interconnection continue to be the ISO. This means that schedules on these two lines would be coordinated with BPA, the ISO, and the California-Mexico Reliability Center.

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Summary Comparison of MSS and Control Area Alternatives

Because of the similarities and subtle differences between the MSS and Control Area alternatives, the following slides are intended to show some of differences between the two alternatives.

Provision/Function	MSS Alternative	Control Area Alternative
Reliability Function	Accountable to the ISO directly under the MSS Agreement. ISO requires MSS to sign RMS agreement with WECC, which then may issue sanctions directly against the MSS. Policies that can be waived are negotiated by MSS and	Accountable to NERC and WECC directly, and is penalized for violations under the Reliability Management System (RMS) agreement between the control area and WECC

	ISO	
Changes in Control Performance Provisions/Requirements	ISO and MSS attempt to negotiate amendments. Changes filed at and concurred in by FERC.	NERC and WECC committees develop policy changes and recommend to WECC board for approval. Changes to performance developed by industry concensus
Maintenance Outages	Coordinated with affected utilities and ISO	Coordinated with neighboring control areas/affected utilities/ security coordinator
Metering	Generation and interconnection flow data telemetered to control center and ISO. Metering to be revenue quality.	Generation and interconnection flow data telemetered to control center. Metering to be revenue quality.
Emergency Operations	Emergency operations plan approved by ISO. ISO directs all emergency operations. MSS must comply with all directives or furnish reasons for non-	Emergency procedures consistent with NERC and WECC policies and are reviewed during certification. Emergency operations coordinated with all

	compliance with ISO.	neighboring control areas and security coordinator.
Deviations from Schedule	Must operate within three percent deviation band if the MSS chooses to load follow or may opt for purchasing imbalances in the ISO markets. Over generation out of the band is lost to the system, while under generation is penalized 200 percent. If poor performance causes ISO sanction, penalties paid by MSS.	Must operate in accordance with WECC and NERC control performance criteria. Imbalances are inadvertent interchange that is accumulated and returned to the interconnection. Operation outside of criteria subject to penalties under RMS agreement.
Scheduling	In accordance with ISO protocols which may be changed by ISO action.	In accordance with WECC protocols as may be changed by industry consensus.
Reserves	Must maintain reserves in accordance with ISO Tariff. Must pay market price for	Must maintain reserves in accordance with WECC criteria. Penalties may be issued

	deficiencies of reserves at market rates.	under RMS agreement.
Neutrality Charges	Pay proportionate share based on net MSS loads	No charges

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Factors to be Considered during Decision Making

As a federal agency, Western has specific statutory duties it must fulfill. As an example, Western is responsible for ensuring that project use energy needs of the CVP are met. As a cost-based entity, Western is responsible for fulfilling these obligations at the lowest rates consistent with sound business practices. As a non-profit entity, Western has an obligation to minimize its exposure to risk and uncertainty to ensure the Federal investment in the project can be repaid by project beneficiaries. In keeping with these duties, Western has identified five basic criteria that will be used in the decision making process. These factors are not exclusive, and are not shown in priority order. Other factors may be identified during this public process, and Western invites your input on additional factors that may have been overlooked and the relative importance of each of the identified criteria. The factors Western has identified are:

1. Flexibility – The utility industry is changing rapidly because of industry initiatives, regulatory pressures, both federal and state, and initiatives by the Federal Energy Regulatory Commission, or FERC, to implement standard market design and encourage formation of Regional Transmission Organizations, or RTOs. Whatever alternative is chosen,

Western must be able to adapt its operation to these initiatives and pressures as the evolution occurs without creating business uncertainty and unforeseen impacts on Western's customers.

2. Certainty – Western and its customers must have stable rates and charges so that business planning can occur and long-term commitments can be made without considerable expenditures for risk management activities that could render some business activities unprofitable.
3. Durability – Operating protocols and requirements are well established and subject to minimal changes over time. Major changes in business processes can have significant impacts on staffing and use of resources that can damage productivity of any organization.
4. Operating Transparency – Changes in operation of the federal system can occur with as little disruption of "business as usual" as possible.
5. Cost Effectiveness – Cost shifts are minimized among Western's customers and, overall, the cost of operation of the system and delivering federal power is as low as possible.

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Some Pros and Cons of Each Alternative

The Participating Transmission Owner alternative, if selected, may result in the lowest labor cost for Western because the ISO will perform the scheduling function, the balancing function, and the reliability function for the federal system. Labor cost savings in the operations area may be reduced, and could be negated, if the ISO rates and cost types continue to increase, due to the need for additional settlement positions to account for federal power deliveries. This alternative also may result in the highest cost of delivery of federal power to all of Western's customers because the federal system would be integrated into the ISO system and all of the various ISO charges will apply to every customer.

The MSS option could shield the participants in the MSS from various ISO charge types if SNR provides the balancing function and reserves for the participants, and could reduce the total reserve requirement for SNR because of the load ratio share approach to ancillary services. Another possible benefit to the MSS alternative is that on January 1, 2005, Western could include all of its customers that want to be participants in the MSS, whereas with the control area alternative, inclusion in the control area will not begin for at least six months after the control area begins operation. However, since the MSS alternative requires an agreement with the ISO, the benefits of the arrangement could erode with time because of ISO tariff changes.

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The control area alternative could also shield the customers included in the control area from various ISO charge types. Inclusion of off-system customers through dynamic scheduling can not be guaranteed, even though it is common utility practice, because this requires agreement with the ISO. As a practical matter, Western may not be able to perform the balancing function for all control area members because of generation limitations. A benefit of the control area alternative is that scheduling protocols, control performance, and other "rules of the road" can only change because of industry consensus, rather than by changes made to the ISO tariff under the MSS alternative.

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Summary

We realize that this is a lot of material to digest this morning. Obviously, SNR staff has been working with these concepts for some time. Our efforts to date have centered on determining what we need from a hardware and software perspective to operate in the post-2004 time frame with the new marketing plan, regardless of which alternative is selected. We have made conscious efforts to prioritize our work effort on systems that are common to any of the alternatives. With few exceptions, no work has been done to date that will be wasted if we choose one alternative over another. A lot of work needs to be done, primarily in the contracts and procedures areas. We are now at the point where our work effort must be focused on the way we will operate in the post-2004 time period. We must make a decision by the end of the year so that all of the systems will be in place and tested when operation begins on January 1, 2005, no matter which alternative is chosen.

To recap, SNR is considering the three alternatives described this morning:

1. To become a Participating Transmission Owner with the ISO;
2. To become a Metered Subsystem with the ISO; and
3. To become a certified control area.

The factors that have been identified to make the decision are:

1. Flexibility;
2. Certainty;
3. Durability;
4. Operating Transparency; and
5. Cost Effectiveness.

Each of the alternatives presented represent some benefits to certain of our customers, depending to a large extent on whether a customer is “in” or “out” of the MSS or control area, with the PTO option seemingly treating all of the customers in a like fashion. Each of the alternatives represents a different set of costs and organizational structure to implement. We seek your input on which alternative Western should select, other alternatives that you believe should be considered, other factors that should be considered in the decision making process, and the relative importance of these factors. Through this process we intend to make an informed decision with the benefit of your thoughts and guidance.

At this time, Shawn Matchim of Navigant Consulting, Inc., will describe the relative economic benefit study on the alternatives I’ve just described. Thank you.