F. Energy provided with firm power will be based upon the customer's monthly system load pattern.

G. Any electric service contract offered to a new customer will be executed by the customer within 6 months of a contract offer by Western, unless otherwise agreed to in writing by Western.

H. The resource pool will be dissolved subsequent to the closing date of the last qualified applicant to execute their respective firm power contract. Firm power not under contract will be used in accordance with the Program.

I. The minimum allocation will be 100 kilowatts (kW).

J. The maximum allocation for qualified utility and non-utility applicants will be 5,000 kW.

K. Contract rates of delivery will be subject to adjustment in the future as provided for in the Program.

L. If unanticipated obstacles arise to delivering hydropower benefits to Native American tribes, Western retains the right to provide the economic benefits of its resources directly to these tribes.

IV. General Contract Principles

Western will apply the following general contract principles to all applicants receiving an allocation of firm power under the Post-2005 Resource Pool Allocation Procedures.

A. Western will reserve the right to reduce a customer's summer season contract rate of delivery by up to 5 percent for new project pumping requirements, by giving a minimum of 5 years' written notice in advance of such action.

B. Western, at its discretion and sole determination, reserves the right to adjust the contract rate of delivery on 5 years' written notice in response to changes in hydrology and river operations. Any such adjustments will only take place after a public process by Western.

C. Each allottee is ultimately responsible for obtaining its own third-party delivery arrangements, if necessary. Western may assist allottees in obtaining third-party transmission arrangements for delivering firm power allocated under these procedures to new customers.

D. Contracts entered into under the Post-2005 Resource Pool Allocation Procedures provide for Western to furnish firm electric service effective from January 1, 2006, through December 31, 2020.

E. Contracts entered into as a result of these procedures will incorporate Western's standard provisions for power sales contracts, integrated resource planning and the general power contract provisions.

F. Contracts entered into will include provisions for a reduction of up to 1 percent of the current contracted rate of delivery effective January 1, 2011, in accordance with the Program.

V. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. Western has determined this action does not require a regulatory flexibility analysis since it is a rulemaking about rates or services for public property.

VI. Small Business Regulatory Enforcement Fairness Act

Western determined this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

VII. Determination Under Executive Order 12866

DOE has determined this is not a significant regulatory action because it does not meet the criteria of Executive Order 12866, 58 FR 51735. Western has an exemption from centralized regulatory review under Executive Order 12866; so, this notice requires no clearance by the Office of Management and Budget.

Dated: November 17, 2003.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 03–29986 Filed 12–1–03; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Operational Alternative for Post-2004 Operations

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed decision.

SUMMARY: The Western Area Power Administration (Western), a Federal power marketing administration within the Department of Energy (DOE), markets Federal power from the Central Valley and Washoe projects through the Sierra Nevada Region (SNR). Western published its Notice of Intent announcing the operational alternatives it was considering for post-2004 operations in the **Federal Register** on June 24, 2003. Western held public meetings in July 2003 and accepted comments through August 8, 2003. Western reviewed the comments and assessed the feasibility of implementing each alternative to reach its proposed decision. Western's proposed decision is to implement a contract-based sub-control area. Western will approach the California Independent System Operator (ISO) and the Sacramento Municipal Utility District (SMUD) to collect data and initiate discussions to develop a contract.

DATES: To ensure they are considered, written comments from entities interested in commenting on this Notice of Proposed Decision must be received no later than 4 p.m., January 2, 2004. Western will accept written comments received via regular mail through the U.S. Postal Service if they are postmarked at least 3 days before such date. Entities are encouraged to hand deliver, use certified mail, or e-mail to deliver comments.

ADDRESSES: Written comments should be sent to Tom Carter, Power Operations Manager, Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, or by e-mail to *tcarter@wapa.gov.*

SUPPLEMENTARY INFORMATION:

Authorities

The selection of an alternative for post-2004 operations is made under the authorities contained in the Department of Energy Organization Act (42 U.S.C. 7101–7352); the Reclamation Act of June 17, 1902 (ch. 1093, 32 Stat. 388) as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Act of 1939 (43 U.S.C. 485h(c)); and other acts specifically applicable to the projects involved.

Public Process

Western published its Notice of Intent to consider certain post-2004 operational alternatives in the **Federal Register** (68 FR 37484) on June 24, 2003. The notice described each alternative and the factors Western would use in making a decision on which alternative to select. On July 9, 2003, Western held a Public Information Forum where each alternative was described, and the evaluation factors that would be used by Western when making its proposed decision were presented. Navigant

Consulting, Inc., (Navigant) presented results from its comparative economic benefits study performed on behalf of the Bureau of Reclamation (Reclamation) and Western. Following the presentations, Western and Navigant staff answered questions from the attendees. A summary of the questions and answers at the July 9, 2003, Public Information Forum are at *http://www.wapa.gov/sn/initiatives/post2004/opScenarios/July9P1responses.pdf*. Western received additional questions after July 9, 2003, and posted responses at *http://www.wapa.gov/sn/initiatives/post2004/opScenarios/pifq-as1.pdf*.

Western held a Public Comment Forum in Folsom, California, on July 30, 2003, during which representatives from 12 entities commented on the proposed alternatives and decision-making factors. As individual stakeholders asked more detailed questions about Navigant's comparative economic benefit analysis, responses were prepared and posted to Western's external Web site throughout the comment period, which closed on August 8, 2003. Western received written comments from twenty-six (26) different entities. Western posted the comment letters at *http://www.wapa.gov/sn/initiatives/post2004/opScenarios/Comments08–08–03/* on August 13, 2003.

Throughout the public comment period, Western received and considered comments from existing power and transmission customers, joint powers agencies, water districts, irrigation districts, the ISO, the California Electricity Oversight Board, the ISO's Market Surveillance Committee, an investor-owned utility, and an independent consumer group. The comments provided the unique perspective of each entity on the various alternatives, provided suggestions concerning the selection of an alternative, commented on the decision-making factors proposed by Western, and raised issues and concerns about implementing an operational alternative.

Decision-Making Criteria

The criteria used by Western to reach its proposed decision are described in the June 24, 2003, **Federal Register** notice and were described in further detail at the July 9, 2003, Public Information Forum. The five criteria are flexibility, certainty, durability, operating transparency, and cost-effectiveness.

Flexibility preserves the ability of SNR to join a Federal Energy Regulatory Commission (Commission) approved and certified Regional Transmission Organization (RTO) in the future and to adapt to ongoing changes in the electric utility industry. At the July 9, 2003, Public Information Forum, Western stated that whatever alternative was chosen, Western must retain its ability to be able to adapt its operations to future changes in the electric utility industry to minimize business uncertainty and impacts to Western's customers.

Certainty assures cost-of-service rates remain stable and predictable. Western further defined certainty at the July 9, 2003, Public Information Forum as having stable rates and charges so Western and its customers will be able to continue engaging in long-term business planning and to undertake prudent long-term commitments under a reasonable risk management planning horizon.

Durability assures operating protocols are well established and subject to minimal changes over time. Western stated at the July 9, 2003, Public Information Forum that this definition also included business processes and observed that major changes in business processes can significantly impair the efficiency and the ability of individual organizations to respond effectively because of the need for increased staffing and resources.

Operating transparency minimizes operating impacts to third parties. Western defined this factor as the ability for Western to change the operation of the Federal system with minimal impacts to third parties.

Cost-effectiveness minimizes cost shifts and considers the relative cost and benefits to SNR's customers. Western stated at the July 9, 2003, Public Information Forum that cost effectiveness included the concept of ensuring that the overall cost of operation of the system and that the delivery of Federal power is kept as low as possible consistent with sound business principles.

Public Comments

Several comments indicated support for Western using the above criteria. Some comments also provided information concerning the relative weighting of the criteria that Western should use. The Transmission Agency of Northern California (TANC) commented that, given the relative instability of the electric utility industry, it is important for Western not to use costs as the only criteria for evaluating each post-2004 operational alternative. Comments from other public agencies such as the Calaveras Public Power Agency, the Modesto Irrigation District (MID), the SMUD, the Silicon Valley Power (SVP), the Trinity Public Utilities District (TPUD), and the City of Redding, indicate a preference for selecting an alternative that is the most flexible, durable, and cost-effective. The Lawrence Livermore National Laboratory (LLNL) commented that Western should further define the above criteria and provide interested parties with the relative weighting Western would use in selecting the operational alternative.

The ISO commented:

> Western initially stated that the decision to form its own control area would be cost based. Now that the real impact of the costs of the various Market Plan options is being understood more clearly, the criteria for this decision seems to have changed. It wasn't until the June 24, 2003, **Federal Register** notice that the public learned for the first time that the factors that it [SNR] will use in its decision-making process are now flexibility, certainty, durability, operating transparency and cost-effectiveness.

The ISO and several other commentors also indicated concerns with grid reliability and complexity of operations and expressed a desire to include reliability as an additional evaluation category. Western did not receive any other suggested additions or changes to its proposed evaluation criteria.

Western's Response

The decision-making factors outline the business reasons Western must consider as it analyzes impacts associated with implementing each specific alternative. These business reasons include the ability to respond to industry changes, having a voice in its own future, providing customers with as stable an environment as possible as industry wide changes occur, and providing customers with products and services at the lowest possible rates consistent with sound business principles. Consequently, when making a decision on its future operations, it is not wise for Western to rely on a single factor. Thus, Western developed additional factors to allow it to continue meeting its statutory requirements and address its long-term strategic goals and objectives.

Western considered the request to include reliability as an additional evaluation category. Western decided not to include reliability as a separate evaluation category because, under existing Western Electricity Coordinating Council (WECC) and North American Electric Reliability Council (NERC) operating guidelines, Western must demonstrate negative impacts will either not occur or will be mitigated before a selected alternative is implemented. Because implementing an alternative must not decrease reliability under WECC/NERC operating guidelines, adopting this evaluation factor as an additional factor in this process is redundant.

Western assumes the ISO reference to Western's initial position that the decision on a post-2004 operational alternative would be based only on cost was the result of a meeting between Western and the ISO in December 2002. At the meeting, Western indicated that any decision related to its future operational configuration would have to be supported by a business case. Western did not intend by its comments that its decision on a post-2004 operational configuration would be based solely on cost.

In addition to the December 2002 meeting, Western participated with the ISO in a joint meeting with the Pacific Gas and Electric Company (PG&E), the Southern California Edison Company, and the San Diego Gas and Electric Company in February 2003. On April 8, 2003, Western met with the ISO to discuss the ISO's Metered Subsystem (MSS) proposal. At the time of these meetings, Western had not yet fully developed all of the evaluation factors it intended to use in its decision-making process.

An oral request by a representative from the LLNL to further define the criteria and to identify the weighting Western would use in making a decision was received at the July 9, 2003, Public Information Forum and considered. Western provided its definition of each criterion at the Public Information Forum and requested written comments on the definitions and the relative importance of each factor. Western did not receive any written comments on any specific modifications to the definitions and their relative importance.

Throughout the comment period, Western did not receive any adverse comments to its proposed evaluation criteria, although it received several requests to consider reliability as a separate factor. Western received many written comments supporting the criteria. Western concludes that the evaluation criteria and their respective definitions are appropriate. Therefore, the evaluation criteria are now final. This decision is based on Western's evaluation of the comments and the fact that Western did not receive a single written comment recommending any changes to the definitions of the existing factors.

The ISO and a number of other commentors expressed concerns that forming a new control area in northern California could compromise the reliable operation of the electric power grid. Specifically, these commentors expressed reservations that under a control area option, this option could increase the complexity of operations and potentially affect reliability. Western views these two concerns as implementation issues, rather than evaluation issues associated with forming a control area, and would be ordinarily resolved as part of the WECC and NERC certification process for formation of a new control area.

Implementing the Post-2004 Power Marketing Plan

For Western to implement its post-2004 Power Marketing Plan, significant investment in new business infrastructure and systems is necessary. This new investment in business infrastructure and systems is independent of Western's selection of a post-2004 operational alternative. Since 1967, Western has operated as a separate, but integrated, subsystem of the PG&E system under the terms and conditions of Contract 14–06–200–2948A (Contract 2948A). PG&E has indicated it is unwilling to continue the terms of that contract. Western, in formulating the new marketing plan for the post-2004 period, based on PG&E's positions, assumed that Contract 2948A would expire and services such as firming energy and ancillary services previously provided by PG&E would have to be either self-provided or purchased in the market. Under Contract 2948A, PG&E provides these services and bills Western monthly. With the increased complexity of the markets and the need to schedule, account for, and settle transactions with the ISO on a 10-minute to hourly basis, Western needs to acquire replacement business systems to provide the same level of technical support for the post-2004 period now provided by PG&E.

One of the biggest changes that Western will face in implementing its post-2004 Marketing Plan is that Western and its customers will be exposed directly to real-time changes in the market. Previously, under Contract 2948A, Western and its customers settled with PG&E on a monthly after-the-fact basis. This change represents a significant departure from Western's current business practices and will require a substantial increase in work effort to implement Western's post-2004 marketing program.

Western recognized its need for new business systems and infrastructure during the development of its new marketing plan. Western embarked upon an effort to identify the requirements to procure and install new business systems that would provide the needed tools for doing business in the business environment under the new marketing plan. The new systems needed to support the new marketing plan, regardless of which operational configuration is selected, include the Scheduling system, the Power Billing system, the Load Forecasting system, the Generation Optimization system, the Enterprise Architecture Integration system, the Meter Data Repository system, and the Settlements system.

The Scheduling system software supports two functional areas, the merchant function and the reliability function, because Western has chosen to follow the spirit and intent of the FERC Order Nos. 888 and 889, which require separation of the merchant function from the reliability function. The merchant function portion of the scheduling system enables the merchant to schedule transactions in the day-ahead markets to deliver Federal power to Project Use loads and Preference Power customers, including the necessary transmission reservations required by Western's energy deliveries and Western's transmission customers.

The reliability function portion of the system provides for real-time implementation of the day-ahead schedules and any real-time modifications to schedules required to balance the control area, sub-control area, MSS, or to accommodate schedule changes by Western's customers, including changes to transmission schedules. This new system is needed to accommodate hourly scheduling and accounting required under the new restructured energy markets, rather than the monthly scheduling and accounting previously required under the terms of Contract 2948A.

The Power Billing system allows Western to gather and process meter data and information from the Scheduling system, bill customers, and generate reports within administratively and contractually required time frames. The Power Billing system used by Western under Contract 2948A requires extensive modifications to accommodate hourly market settlements under current utility settlement standards. This major upgrade will allow Western to accurately bill and account for any of the alternatives under consideration.

The Load Forecasting system will enable Western's merchant function to forecast the load of customers who have requested portfolio management services under the Full Load Service option in the new marketing plan. As the portfolio manager for these customers, Western will need the ability to accurately forecast load requirements to optimize power purchases and minimize costs. Under Contract 2948A, since Western was not the load serving entity for these customers, it had no responsibility to meet customer loads other than to reduce load whenever energy deliveries to its customers exceeded Contract 2948A's maximum simultaneous demand level.

The Generation Optimization system is another new system that will enable Western and Reclamation to maximize the value of the hydropower generation from each Central Valley Project (CVP) power plant. Using the required daily water releases and hourly energy price forecasts, the Generation Optimization system will develop a water release schedule, which still allows Reclamation to meet its daily water delivery obligations, while simultaneously maximizing the value of the hydropower generation. When Contract 2948A expires, PG&E will no longer integrate CVP's hydropower generation with its own resource portfolio. Consequently, Western will need to have the optimization capability to maximize the value of the hydropower generated from the project's facilities.

The Enterprise Architecture Integration (EAI) is a software integration system and serves as the communications backbone for the different software packages. EAI allows data sharing and coordinates/integrates the interaction between other software programs to develop reports and analytical studies that support day-to-day business operations.

The Meter Data Repository system will allow Western to collect metered quantities from its delivery and interconnection points. Collecting this data will allow Western to analyze system performance and support its day-to-day operations. The information stored in the data repository will be used by the maintenance, operations, and power billing functions to conduct day-to-day operations to ensure that Western's transmission facilities continue to operate reliably and in conformance with all applicable NERC and WECC operating criteria. In addition, the metered data quantities will be used in Western's power rates function to support cost-of-service determinations.

The Settlements system will allow Western to keep track of its transactions with the ISO for each commodity purchased or sold in the ISO markets. Western's existing system is inadequate for post-2004 operations since significant amounts of data need to be entered manually, and the current application is not easily integrated with other business applications/systems. A replacement system capable of automatically integrating data from other business information systems is required.

Western requires each identified system to meet the statutory obligations associated with implementing its post-2004 Marketing Plan regardless of which operational alternative it selects. Because of the projected cost of the identified systems and resultant budget impact, Western worked with its customers during calendar year 2001 to secure additional funds to implement its new marketing plan. Customers recognized this need and provided more than $19 million to develop and implement these new business systems in fiscal years 2002–2004.

Comparative Economic Benefits Study

Navigant prepared a comparative economic analysis of each post-2004 operational alternative under consideration as part of this public process on behalf of Reclamation and Western. Navigant's initial comparative analysis showed that, of the three alternatives, the comparative net benefits of Western operating as either an MSS in the ISO control area or as a new control area were similar. Navigant's analysis indicated the Participating Transmission Owner (PTO) Alternative was the least cost-effective option.

During the public comment period, the ISO and other commentors questioned some of the underlying assumptions used in the Navigant study. The ISO submitted a separate economic analysis showing the PTO and MSS options were the least-cost options. Navigant reviewed the assumptions used in the ISO's studies and the comments received on its study assumptions. As a result, a number of assumptions in Navigant's initial economic comparative benefits study were changed. The revised study indicates from an overall comparative economic standpoint, the PTO option continues to remain the least cost-effective of the three alternatives being considered.

The revised comparative benefits study incorporated the following recommended changes to the assumptions: (1) Changing the treatment for self-provided ancillary services to correct a misinterpretation of the ISO Tariff, (2) changing the operating reserve requirement under the Federal control area option to be the greater of 5 percent or the largest single contingency, (3) increasing Western expenses to escalate these costs at the rate of inflation, (4) changing the assumption to include all transmission revenues on the 94-mile section of the Pacific AC Intertie (PACI) line between Malin and Round Mountain substations, (5) changing the assumptions regarding reliability services charges to eliminate charges for direct-connected customer loads, and (6) changing the congestion charges applied to Western loads to reduce net congestion charges to 80 percent of the total charges.

The comparative economic benefit analysis estimated the comparative costs Western would incur under each proposed post-2004 operating alternative over a 15-year analysis period. The nominal values identified in the Navigant comparative economic benefit study were discounted at a Federal discount rate of 5.6250 percent to determine annualized benefits and costs. The annualized results of the study are summarized below:

ANNUALIZED COSTS ASSOCIATED WITH IMPLEMENTING AND OPERATING EACH POST-2004 ALTERNATIVE

[In millions of dollars]

	Participating transmission owner option	Metered sub-system option	Federal control area option A	FCA option B	FCA option C	FCA option D
Total Benefits	88.1	76.7	81.6	81.6	81.6	81.6
Total Costs	98.8	85.6	91.1	90.5	90.4	63.1
Net Benefits	(10.7)	(8.9)	(9.5)	(8.9)	(8.8)	18.5
Net Benefits Normalized to PTO Option	0.0	1.8	1.2	1.8	1.9	29.2

The benefit calculation included estimates for sales of ancillary services, payments for transmission access charges, and transmission capacity sales. The cost components included estimates for the following ISO charges: ISO grid management charges, ISO transmission services, purchases of ancillary services from the ISO markets, transmission congestion charges, reliability services charges, energy imbalance/deviation charges, unaccounted for energy charges, neutrality charges, and grid operation charges. The study also includes Western's estimates of the capitalized infrastructure investment costs, annual operating expenses, and estimated transmission revenue requirements. The comparative economic analysis normalized the net benefits under each alternative against the cost of implementing the PTO option. Under this cost normalization approach, avoided costs associated with implementing each post-2004 operating scenario show avoided annual costs of approximately $1.8 million for the MSS option and a range of $1.2 million to $29.2 million in avoided annual costs for the control area option. The cost avoidance range for the control area formation options result from decreasing ISO charges levied as more CVP customers join the new control area. The control area option analyzed four alternative scenarios. Scenario A assumed formation of a control area which included only the direct-connected Reclamation Project Use loads. Scenario B assumed formation of a control area which included Scenario A and three direct-connected Preference customers (Cities of Redding, Roseville, and Shasta Lake). Scenario C assumed all elements from Scenario B and added the following three other direct-connected customers: the Turlock Irrigation District (TID), the MID, and the SMUD. Scenario D assumed the inclusion of all other Preference Power customers. The avoided costs increase across the scenarios as the fixed costs of forming and operating the proposed control area are spread over a larger base, and the amount of charges that control area participants are responsible for paying to the ISO decrease.

Excluding baseline operation and maintenance expenses, which would be the same under all post-2004 operational alternatives, an estimate of annual operating expenses associated with each alternative was developed. The table below summarizes Western's estimated cost for each post-2004 operational alternative.

POST-2004 OPERATIONAL ALTERNATIVES COST SUMMARY ESTIMATED ANNUAL EXPENSES

[In millions of dollars]

	Participating transmission owner option	Metered sub-system option	Federal control area options (A–D)
Annual Operating Expenses	10.1	16.2	17.5
Annualized Capital Expenses:			
Information Technology	2.8	2.8	3.2
Other Infrastructure	0.2	0.2	0.3
Substation Costs	0.0	0.7	2.8
Subtotal	3.0	3.7	6.0
Other One-Time Expenses:			
Western Metering	0.0	0.0	1.0
Reclamation Metering	1.3	1.3	0.9
Subtotal	1.3	1.3	1.9

As discussed previously under the section entitled ''Implementing the post-2004 Power Marketing Plan,'' much of the Information Technology infrastructure is required to implement the post-2004 Power Marketing Plan. The only differences relate to capital investments required to support specific functionality in software, metering equipment, and substations. Operating expenses are significantly lower under the PTO option because there is no need to incur additional expenses in the maintenance and operations functions. Specifically, the MSS and control area options require two additional 24-hour desks (Transmission Scheduling and Security and Automatic Generation Control) and additional expenses associated with maintaining facilities at Cottonwood (MSS Alternative) or Cottonwood and Round Mountain substations (Control Area Alternative) in the event Western is unable to successfully negotiate a contract-based path to the Pacific Northwest.

Although Western may ultimately need part of both Cottonwood and Round Mountain substations to implement the MSS Alternative, Western decided to take a more conservative cost approach for the initial comparative cost studies. If Western decides to implement the MSS Alternative in the future, Western may consider including Round Mountain Substation as a northern boundary point. Finally, the MSS and control area options require additional staff to handle settlements with the ISO. The Navigant study only analyzed the costs that Western would incur as a transmission provider under each post-2004 operations alternative and, consequently, did not estimate the costs that individual customers would incur under each operating scenario.

Under the MSS and the control area formation options, Western assumed that to perfect its existing rights under Contract 14–06–200–2947A (Contract 2947A) it would be required to either acquire or invest in constructing alternative facilities at, or in the vicinity of, Cottonwood and Round Mountain substations. This would assure a contiguous path between Western's transmission system and the Pacific Northwest.

Executing a PTO agreement would result in blending the relatively low costs of Federal transmission facilities with the higher statewide costs of California's three investor-owned utilities. This would result in an increase in costs to Western's Preference Power customers and Reclamation's Project Use loads without a corresponding increase in benefits.

Description of Alternatives

The No Action Alternative

Under the No Action Alternative, Western would not undertake any actions before January 1, 2005, to establish a successor operational configuration or to develop and establish permanent new business arrangements with the ISO or PG&E, based on PG&E's position that it will not extend the terms of Contract 2948A. Under Reclamation law, Western is responsible for marketing and transmitting Federal power, but because it would not have a long-term business arrangement in place with the ISO or PG&E, Western would not be able to guarantee delivery of Federal power to Project Use loads from delivery points in the ISO control area.

Deliveries on the California-Oregon Intertie (COI) lines could also be affected negatively as successor interconnection and/or transmission arrangements would not be in place. Western recognized the problems associated with this alternative before publishing its June 24, 2003, **Federal Register** notice. With no successor interconnection and/or transmission arrangements in place, under the No Action Alternative, the parties may have no other alternative but to seek the clarification and resolution of their respective interests through litigation. The June 24, 2003, notice stated:

> Since a basis for transactions or business relationships necessary to carry out deliveries of power to customers does not exist, substantial business uncertainty would result. One or more of the parties could pursue litigation to determine the respective positions of Western and its individual customers, Reclamation, CAISO, and PG&E. This alternative creates business uncertainty and operational impediments which would result from not having successor agreements in place with PG&E and the CAISO.

Operating Scenario To Evaluate the No Action Alternative

Under the No Action Alternative, Western would be a contiguous electrical system with most of Reclamation's generation and Reclamation's single largest Project Use load (Tracy Pumping Plant), as well as some Preference customer loads directly connected to the Federal transmission system. Reclamation's off-system generation at San Luis and New Melones would continue to operate under terms of existing contracts with PG&E that do not expire until 2016 and 2028, respectively. Western's northern boundary for its transmission system would be uncertain because of the lack of successor transmission arrangements to Contract 2947A at Round Mountain and Cottonwood substations.

Since Western would not undertake actions to implement a post-2004 successor operational alternative, it would continue to reside within the ISO control area. Under the No Action Alternative, Western would not have long-term business arrangements that would allow it to deliver Federal power to Project Use loads, First Preference, and Preference Power customer loads not directly connected to Western's transmission system. Western would execute short-term (non-firm) transmission arrangements with the ISO, typically one day at a time, and would be subject to curtailments whenever congestion or other operational constraints arise.

Without long-term business arrangements, the ISO would not be obligated to provide services to Western. The converse is also true for Western. In the absence of long-term arrangements, Reclamation would not execute a Participating Generator Agreement (PGA) with the ISO. Revenues associated with generation or ancillary services excess to the needs of direct-connected Project Use loads and Preference Power customers and sold to the ISO for its needs would not be available to Western. Western would exist within the ISO control area without specific boundaries, and without the ability to collect revenues associated with services provided to the ISO, or to deliver power on a sustained basis to meet Western's statutory and contractual obligations to off-system Project Use loads, First Preference customers, and Preference Power customers, respectively.

Evaluation of the Flexibility Criteria Under the No Action Alternative

The No Action Alternative would give Western very little certainty in conducting its day-to-day business operations. Without long-term business arrangements, Western would have to rely on short-term arrangements with the ISO and others after January 1, 2005, to continue to do its business. Although these short-term arrangements do not commit Western to a long-term relationship and allow Western to modify its operations, the arrangements are inherently unstable and create significant business uncertainty. Thus, the No Action Alternative does not meet the flexibility criteria.

Evaluation of the Certainty Criteria Under the No Action Alternative

The No Action Alternative does not assure a stable business environment for Western or its customers. With no long-term business arrangements, Western would have no basis for requiring the ISO or PG&E to deliver power to Western's off-system Project Use loads or Preference Power customers served using the ISO-controlled grid. On January 1, 2005, Western would not have negotiated long-term mutually beneficial business arrangements with the ISO or PG&E and, consequently, would have to undertake short-term and potentially unstable business arrangements to deliver Federal power to Project Use and Preference Power loads not interconnected to the Federal transmission system. There would be no long-term rate certainty and, in the event rates increase faster than Western's ability to undertake changes through its formal rate-setting process, Western would face the potential of significantly reducing its power deliveries to avoid any potential violations of the Federal Anti-Deficiency Act. The underlying uncertainty would also inhibit long-term business planning and, as a result, Western concludes that the No Action Alternative does not meet the certainty criteria.

Evaluation of the Durability Criteria Under the No Action Alternative

Under the No Action Alternative, Western would not have any operational protocols or business processes in place as of January 1, 2005. Effective this date, Western would put interim business procedures in place to continue operating in the ISO control area. Because short-term arrangements are by their nature unstable, given the unique nature of the CVP hydropower system, unsettled rights on the COI, and the lack of a northern boundary for Western's transmission system, Western concludes that the No Action Alternative does not meet the durability criteria.

Evaluation of the Operating Transparency Criteria Under the No Action Alternative

Under the No Action Alternative, as of January 1, 2005, Western would have no long-term business arrangement with the ISO for operation of Western's transmission system within the ISO control area. Since Western would not have a long-term business arrangement with the ISO, every transaction would be accomplished on an interim, short-term basis. Under this scenario, Western would not be able to guarantee delivery of Federal power to Project Use loads and meet its contractual commitments to First Preference and Preference Power customers to deliver energy to delivery points on the ISO-controlled grid since it could buy transmission on only a non-firm basis.

In addition to the uncertainty associated with Western's business relationship with the ISO, other uncertainties include the lack of successor transmission arrangements to Contract 2947A for continued transmission access to the PACI line, lack of successor operational arrangements (Coordinated Operations Agreement) for the coordinated operations of the three-line COI, and potential new business arrangements on the California-Oregon Transmission Project (COTP). As a result of these business uncertainties under the No Action Alternative, Western cannot guarantee that its operations will not negatively impact the operations of third parties and, consequently, Western concludes that this alternative does not meet the operating transparency criteria.

Evaluation of the Cost-Effectiveness Criteria Under the No Action Alternative

Under the No Action Alternative, since Western will not have long-term successor business arrangements with the ISO or others, the cost of conducting its day-to-day business activities is highly uncertain. In addition, since no business relationship exists with the ISO, Western may not be able to realize the benefits of providing products for use in the ISO's markets. For instance, because of the lack of a long-term business arrangement such as a PGA, revenues associated with excess generation and ancillary services provided to, and which may be used by the ISO, may not be fully realized by Western. The ISO may furnish products and services to Western and its customers without a contractual relationship that would allow the ISO to bill Western for the use of such products and services.

Other business arrangements including the acknowledgment of Western's rights to transmission capacity on the PACI, potential new business arrangements on the COTP, successor arrangements for the coordinated operations of the COI, as well as receiving credits associated with self-provision of ancillary services remain uncertain under the No Action Alternative. Without a vehicle to bill or to be paid for services, the economics of Western's operations associated with this alternative are unknown. Because of the uncertainty associated with the cost structure that Western would experience under the No Action Alternative, this alternative does not meet the cost-effectiveness criteria.

Summary Analysis of the No Action Alternative

The No Action Alternative outlined during this public process is unlike other no action alternatives usually associated with a proposed project or policy. In a normal no action alternative, the status quo is preserved and proposed project/policy alternatives are compared with the status quo. In this case, the status quo does not represent the no action alternative as existing contracts with PG&E terminate while Western is simultaneously implementing a new marketing plan. PG&E has explicitly stated that it is not interested in extending or renewing these contracts. With the status quo not available as an option, Western must move toward establishing a new business identity and/or business operating arrangement that will allow it to continue doing its day-to-day business. Taking no action prior to January 1, 2005, will require Western to put in place some type of arrangement to operate within the ISO control area as soon as possible after January 1, 2005.

The No Action Alternative will place Western in a highly undesirable business posture. Without long-term business arrangements in place, Federal power resources cannot be delivered reliably and cost-effectively to Project Use, First Preference Power, and Preference Power delivery points located on the ISO-controlled grid and not directly connected to the Federal transmission system. Lack of any permanent business arrangements would not allow Western to participate in the ISO markets and allow excess generation and ancillary services to be sold and the revenues used to accelerate repayment on the Federal investment. The No Action Alternative impacts Western's ability to meet its statutory obligations to provide energy to Project Use loads on the ISO-controlled grid and meet its contractual obligations to deliver Federal power to First Preference and Preference Power customers who use the ISO-controlled grid. Western has determined that it is not prudent to implement the No Action Alternative.

Western's analysis of the five evaluation factors is summarized in the table below:

NO ACTION ALTERNATIVE EVALUATION SUMMARY

Evaluation factors	Meets	Almost meets	Does not meet
Flexibility			XX
Certainty			XX
Durability			XX
Operating Transparency			XX
Cost-Effectiveness			XX

The Participating Transmission Owner Alternative

Western would execute a Transmission Control Agreement (TCA) with the ISO under the PTO Alternative. Executing a TCA would transfer operational control over Western's transmission system to the ISO. Reclamation would execute a PGA with the ISO. Executing a PGA would allow the ISO to control Reclamation's generation and allow Western to fully participate in the ISO markets by receiving revenues associated with any excess generation.

The CVP was authorized primarily as an irrigation project. Therefore, Project Use energy requirements have first priority for the hydropower generated from the facilities. Hydropower generation in excess of Project Use energy requirements is available to be sold to CVP Preference Power customers. This legislative requirement would need to be appropriately accommodated in any future agreement executed between Reclamation, Western, and the ISO. The specific terms and conditions relating to ISO operational jurisdiction over Federally owned generation and transmission facilities would also need to be carefully evaluated to assure that as a result of implementing this alternative, the authorized project purposes of the CVP are not impaired.

If the appropriate arrangements were worked out with the ISO, at a minimum, Western would need to retain responsibility and operational control over switching operations and the maintenance and replacement of its transmission facilities. Similarly, Reclamation would also, at a minimum, need to retain responsibility and operational control over its hydropower facilities/operations and the maintenance and replacement of its generating facilities. Under existing authorizations, the responsibility and operational control over the water and power operations of the CVP cannot be impaired.

The ISO would become responsible for scheduling the use of the CVP transmission system and Western's

Malin-Round Mountain transmission line. Western currently is the operating agent for COTP. Depending on the arrangements that would ultimately be made for this line, the ISO may also assume operational control of this transmission line. Under its current COTP agreements with TANC, Western would retain responsibility for furnishing technical services associated with the long-term maintenance and replacement of these facilities. The ISO would assume scheduling responsibility for the entire three-line COI system south of the Oregon border and would continue in its role as the single path operator.

Operating Scenario To Evaluate the PTO Alternative

Under the PTO Alternative, Western would not have a physically discrete and defined transmission system. From an operational perspective, Western's transmission system would be integrated with the ISO control area. Western would schedule energy deliveries for Project Use loads, First Preference customers, and other Preference Power customers with the ISO under generation schedules developed by Reclamation and Western. Western would act as the Scheduling Coordinator (SC) for these deliveries and pass through ISO charges associated with generation, including imbalance energy charges, reserve charges, and other charges required to meet the ISO's costs of operating the control area. Western's customers, including those that are directly connected to the Federal transmission system and those served through PG&E facilities, would be billed all of the appropriate ISO charges associated with those energy deliveries. Western would identify its transmission revenue requirements which would be collected by the ISO.

From an operational perspective, Western would need a 24-hour Merchant Desk to purchase energy required to support Project Use energy requirements, as well as to meet the supplemental energy needs of Western's Variable and Full Load Service customers under its post-2004 Marketing Plan. Western would provide SC services for Variable or Full Load Service customers requesting this service, as well as for Reclamation's generation facilities. Under its current operating procedures, the ISO requires each SC to maintain a 24-hour Merchant Desk in order to maintain SC certification status.

Western would also have to maintain a 24-hour Switching Desk to perform switching for outages of system elements (such as transmission lines and breakers) for maintenance, repair, or replacement, or to assist the ISO in restoring the system following a disturbance. Since the ISO would schedule the use of Western's transmission system, Western would not have to maintain a 24-hour Transmission Scheduling Desk. Western would also not have to maintain a 24-hour Automatic Generation Control (AGC) Desk because Reclamation's generation would be dispatched by the ISO under a PGA. As a third party to this transaction, Western could face increased risk and uncertainty as it implements its new marketing plan since it would not necessarily have direct real-time knowledge about the operation and generation status of Reclamation's hydropower facilities.

From an organizational perspective, Western would still need to retain its power accounting, billing, and settlements functions to monitor and credit/bill for products and services purchased and sold under to its marketing plan, as well as to reconcile ISO billings. Staff would be required to verify the accuracy and integrity of the accounting records and issue invoices to Western's customers and the ISO as appropriate. The ISO now has more than 100 separate charge types. Depending on the nature and complexity of the future financial settlements, this function may require additional staffing above current levels.

Evaluation of the Flexibility Criteria Under the PTO Alternative

Implementing the PTO Alternative would subject Reclamation and Western to the terms of the ISO Tariff for the term of the PGA and the TCA, respectively. Western and Reclamation would conform their business practices to those required under the ISO Tariff. If a new RTO is established and the ISO chooses to join, any changes that the ISO would need to make to its existing operating and business protocols would also have to be made by Reclamation and Western. Western and Reclamation would have to either comply with any changes required within the time frames established by the ISO or choose to terminate the TCA and PGA, respectively. Because of the present 2-year notice requirement, the effective date of the termination is not immediate. In the interim, as a PTO, Western and Reclamation would need to conform their business practices to the extent not precluded by Federal law.

If the ISO is certified by the Commission as an RTO, any changes that the ISO would need to make as a result of its new role would presumably be incorporated in its tariff. Reclamation and Western could choose to either undertake the necessary changes in their respective business processes or choose to terminate the PGA and TCA, respectively. Because of the notice requirement, the effective date of the termination would not be immediate. In the interim, as a PTO, Western and Reclamation would need to conform their business practices to the extent not precluded by Federal law.

The electric utility industry is in a state of ongoing change. New policies, procedures, and practices are being adopted to reform and restructure the energy markets. NERC and WECC are coordinating industry wide changes to existing operating standards and protocols to ensure the continued reliable operation of the electric power grid. As industry wide consensus is achieved, under the PTO Alternative, the ISO would presumably modify its tariff as needed.

The flexibility to join whatever RTO that Western chooses is of concern to some of the commentors. For instance, the TID commented ''A [Federal Control Area] FCA allows for choice concerning which Regional Transmission Organization (RTO) Western [Sierra Nevada Region] SNR joins. Other alternatives require that Western joins the RTO that the CAISO desires.''

The TID continued:

> TID believes that the customers of Western should be able to choose what business environment they prefer to operate within. Customer choice was the linchpin in many arguments advocating competitive markets and California's electric industry restructuring. A Western FCA will give customers a choice between operating under the volatile CAISO market structure and a cost based, relatively predictable model. Under a Western FCA, customers will have the choice of participating and being a part of the CAISO if they choose. If Western chooses any of the options that make it subordinate to the CAISO or the CAISO Tariff, Western will have made the choice for many Western customers.

Under Contract 2948A, transmission and ancillary services are provided by the ISO to PG&E on behalf of Western. Western's off-system customers receive transmission service from the ISO and through Western under Contract 2948A. Direct-connected customers receive transmission service and ancillary services from Western and the ISO through PG&E, respectively, under Contract 2948A. When Contract 2948A terminates on January 1, 2005, under this alternative, these services would be provided by the ISO to all of Western's customers unless the customer can self-provide some of these services. In essence, all of Western's customers will be, by default, subject to the charges associated with the ISO Tariff. The TID appears to equate the lack of choice with a lack of flexibility to choose when they enter or leave the ISO environment.

Western believes that choosing the PTO Alternative would give it the short-term flexibility needed to adapt to NERC and WECC policy changes. The long-term flexibility of joining whatever RTO Western chooses is minimally constrained by the current 2-year TCA termination notice. Western, therefore, concludes that the PTO option meets the flexibility criteria.

Evaluation of the Certainty Criteria Under the PTO Alternative

Under the PTO Alternative, Western would be subject to all of the ISO charges associated with being the SC for Reclamation to schedule Base Resource and Custom Product to its customers. The SC for each customer would be subject to all of the ISO charges associated with scheduling and delivering power to the customer's delivery point and the associated ancillary services. Many of the ISO charges, such as imbalance energy and reserves, fluctuate on a daily basis with spot market price variations. Although a portion of this risk may be minimized through forward purchases, this alternative does not provide Western with the ability to load follow. Unanticipated energy imbalance charges may still arise as a result of normal project operations. Transmission and delivery-related charges as well as overhead charges of the ISO may change less frequently, but based on historical trends, these costs are expected to change more frequently than Western's.

The ISO is in the midst of implementing new operating guidance for its Market Redesign (MD02). The proposed new initiative would implement the concept of locational marginal pricing to deal with transmission congestion. If MD02 is implemented in its current format, during periods of congestion, the ISO would redispatch all generation based on economic factors. Under this alternative, during periods of congestion, affected CVP Preference Power customers and Project Use loads could end up paying a different price than the actual cost-of-service rates associated with Federal hydropower resources. These rates may not be consistent with Reclamation law and policy, and Western may need to consider mitigation strategies.

Several of Western's customers are concerned with the predictability and stability of any alternative selected by Western. The TID summarized its view of certainty by stating that under the PTO option, the cost of power from generation to load will be set by a market that cannot be forecast with any certainty. The TID also commented that the Western rate process is open and generally results in a fair allocation of costs based on cost causation principles. The TID contrasts the Western process with the ISO stakeholder process as follows:

This can be contrasted to the CAISO method of allocating costs, which does not accept meaningful direction from stakeholders representing consumers. Rather, the CAISO seems willing only to socialize costs in order to make it seem that the costs of CAISO services are less prohibitive.

The TID also states that transmission allocation based on firm physical transmission rights adds certainty to long-term and short-term planning. TANC commented:

Firm physical transmission rights are a prerequisite to a stable forward energy market. With known physical rights there is no need for unpredictable congestion management schemes, multiple markets, and there is no fictitious congestion. Without firm physical transmission rights it is commercially imprudent to contract in the forward markets. The CAISO provides transmission for a maximum period of one day, and those who are willing to pay the most get to use the transmission grid.

The City of Palo Alto stated:

The City values long-term transmission contracts for establishing firm transmission rights and obligations of load serving entities. Western has always utilized this approach to deliver Western energy to its customers. This provides cost and operational certainty that the CAISO Tariff, and market cost based approach to service, does not provide.

The TPUD commented:

The Cal ISO prepares rate amendments on an average of one every three to four weeks. By contrast, Western ratemaking occurs an average of once every three to four years. The Cal ISO has some 250 different rates. Even with a Federal control area it is doubtful that Western will have a tenth as many.

The Arvin-Edison Water Storage District stated:

Despite the best of intentions and a talented staff, the California Independent System Operator (CAISO) is mired in unwieldy governance that results in perpetual tariff revisions and market redesigns. Each revision results in added costs and complexity that bog the CAISO with some of the highest overhead expenses, and hence the highest grid management costs of any current ISO or RTO in the nation.

Reclamation stated:

Costs of CVP operation have not changed significantly except due to escalation or increased maintenance as the facilities have aged. This situation would change significantly should the CVP become a part of the CAISO. As the largest CVP load, Reclamation does not want the CVP beneficiaries to be exposed to CAISO operational costs beyond what the historical CVP cost of operations have been.

The ISO commented:

The ISO's transmission rates are based on Commission approved cost-of-service basis and on an open and non-discriminatory basis to all market participants * * * the only volatility Western would experience is through buying and selling in the ISO's Ancillary Services and Real-Time Imbalance Energy markets. However, this volatility is present regardless of whether or not Western becomes a control area, and the degree of volatility is based on Western's need to procure additional resources. If Western has sufficient resources, the volatility of these markets would not impact Western and its customers.

Under the PTO Alternative, although Western may retain its ability to purchase power in the forward markets to reduce energy imbalance charges during real-time operations, since Western would not be able to load follow, it would not have the ability to respond to significant changes during real-time operations. Consequently, to the extent that Western is short resources, Western would be subject to any volatility in the ISO's ancillary services and real-time energy imbalance markets.

Western must set its rates at the lowest possible level consistent with sound business practices, but must cover all of its costs, including amounts to repay the project investment over the prescribed repayment period. In the past, Western's costs have been stable with rate adjustments made on an average of once every 3 years. Western's rates are set in an open public process designed to assure that customer concerns are accommodated through an appropriate rate design and cost allocation methodology.

The rate certainty associated with each of the operational alternatives is important in the post-2004 time period. Rate changes could occur more frequently if Western chose an operational alternative where it is subject to more frequent changes in cost. Under the PTO option, Western would be subject to changes in ISO costs that are not within Western's ability to control. For example, between 1999–2002, the ISO revenue requirement for grid management charges increased from $158.7 million to an estimated $239.2 million, an increase of more than 50 percent. Western's customers have expressed an intense interest in assuring that the post-2004 operational alternative selected is responsive to cost containment principles so that to the maximum extent practicable, the rates for products and services are stable and business certainty is maintained.

The commentors quoted previously also equated certainty with having physical long-term transmission rights. These physical rights are unavailable from the ISO under the PTO Alternative. As pointed out by TANC, transmission service is only available on a day-to-day basis and is allocated to those willing to pay the highest price. There is no business certainty associated with a forward purchase that requires transmission to get power to load if, day-to-day, the price of transmission varies significantly. A forward purchase of energy believed to be economical under one set of assumed transmission costs can rapidly become uneconomical if the cost of transmission increases significantly over a short period of time. Under the PTO Alternative, customers would be subject to these variable changes in transmission service costs because the use of Western's transmission system would be governed by the ISO and would be subject to all of the ISO charges. To the extent existing right holders may be eligible to receive congestion revenues, they may be able to mitigate some of this price uncertainty but not to the same extent provided by physical transmission rights.

Under the PTO Alternative, Western would also be responsible for paying ISO overhead charge increases as the SC for Base Resource and Custom Product schedules. If Western does not incur significant energy imbalance or ancillary service charges from the ISO, Western's costs may not escalate as rapidly and be as variable as the ISO's in the recent past. However, Western's customers could experience additional costs associated with the transmission and delivery of their energy due to market-based charges for congestion and ancillary services. Although prices are relatively stable now, Western and its customers may still be subject to uncontrollable market-based risk, as well as the uncertainties associated with the implementation of MD02. Western concludes that this alternative does not meet the certainty criteria.

Evaluation of the Durability Criteria Under the PTO Alternative

In general, operating and business protocols and practices are established and defined by the agreements which create the relationship. These agreements establish obligations and responsibilities of the parties and allocate the burdens and benefits of each business relationship. Under the PTO option, the basis for Western's relationship with the ISO is the ISO Tariff. Because the ISO is a tariff-based organization, after a PTO executes a TCA, the operating terms, conditions, rates, and other pertinent aspects governing a PTO's business arrangements with the ISO can change with the filing of new ISO Tariff amendments. In the event Western and the ISO cannot agree upon potential changes to its existing agreement(s), the ISO can submit its proposed changes to the Commission for resolution.

Many commentors expressed reservations about the durability of any arrangement with the ISO because it uses a tariff-based approach. Many of the comments equated stable, long-term business relationships occurring through contract- and not tariff-based relationships.

For instance, the TANC stated:

> We believe in the durability of long-term contracts for establishing rights and obligations of load serving entities. Western has always utilized this approach to doing business. The CAISO has historically attempted to alter the rights and obligations of existing contracts. The CAISO utilizes tariffs that can and have been frequently changed. The CAISO files amendments too frequently to consider the CAISO Tariff durable or predictable.

Others including the MID, the TID, and the SVP cite the 55 amendments that the ISO filed at the Commission in the last 5 years as evidence that a relationship with the ISO is not durable.

The ISO commented:

> The ISO's operating protocols have remained substantially the same since the ISO start-up date in 1998. The only changes in operating protocols are based on the need to comply with changing operational criteria from the NERC and WECC. However, every control area, including the Western Control Area, would have to make similar changes over time. Admittedly, the ISO has necessarily changed the protocols associated with markets, market implementation, and market rules a number of times over the past 6 years. Given that the ISO was the first of its kind in the United States, an evolutionary process has been necessary when it comes to markets. Thus Western's concern with durability with respect to operating protocols has been met, but market durability is still evolving and will continue to evolve for a number of years to come. Western cannot disguise its concern regarding "operating protocol durability" as an off-hand reference to the energy crisis and changing market rules. Moreover, the ISO's ongoing market modifications are designed to promote stability based on experience, best practices, and coordination of operations to the benefit of all California consumers and market participants.

Fifty-seven ISO Tariff amendments have been filed since the ISO became operational in 1998. Western notes that the ISO has filed four tariff amendments since this public process began on June 24, 2003. Although it is important to distinguish between procedural and substantive changes to the ISO Tariff, the underlying ability of the ISO to undertake changes to its business and operating protocols and procedures creates business uncertainty and risk.

Based on the affected term or condition, these changes could materially affect the relationship between the benefits and burdens that each party would receive and impart from being a PTO. Stakeholders continue to have ongoing concerns related to the frequency and number of ISO Tariff amendments. Although many of these changes would parallel changes that other control area operators must implement in response to ongoing industry changes, because of their frequency and the number of substantive changes made, Western concludes that the PTO Alternative almost meets the durability criteria.

Evaluation of the Operating Transparency Criteria Under the PTO Alternative

As a PTO, Western's transmission system would be scheduled and dispatched by the ISO as a part of the ISO-controlled grid. Assuming that the operational jurisdictional issues identified earlier in the description of the PTO Alternative are satisfactorily resolved, Western and Reclamation would operate its system under the operating protocols and procedures established by the ISO. Because the ISO is a NERC- and WECC-certified control area, the ISO would, in the ordinary course of its business, coordinate changes to its system operations with bordering control areas or provide appropriate mitigation measures to minimize the impacts of such changes to neighboring control areas. With respect to impacts to third parties, the PTO Alternative meets the requirements of the operating transparency criteria.

Cost-Effectiveness Criteria Under the PTO Alternative

Navigant prepared a comparative economic analysis of each post-2004 operational alternative under consideration on behalf of Reclamation and Western. Navigant's comparative analysis showed that, of the three alternatives, the comparative net benefits of Western operating as either an MSS in the ISO control area or as a new control area were similar. Navigant's analysis indicated that the PTO option was the least cost-effective.

During the public comment period, the ISO and other commentors questioned some of the underlying assumptions used in the Navigant study. The ISO submitted a separate economic analysis showing that both the PTO and MSS options were the least cost options. Navigant reviewed the assumptions used in its initial comparative economic benefits study. A number of the suggested changes were accepted and incorporated into a revised comparative economic benefits study. The revised study continues to indicate that from an overall comparative economic standpoint, the PTO option continues to remain the least cost-effective of the three alternatives.

During the public process, some views expressed on the comparative economic benefit studies performed by Navigant and the importance of the cost-effectiveness criteria included:

The TANC commented:

> * * * given the rapid escalation of the CAISO costs, numerous inaccuracies of CAISO settlements, and extreme complexity and variability of CAISO market design, assumption-based cost forecasts in the CAISO environment are difficult to estimate and cannot be the most important evaluation criteria for Western and its Customers.

The TPUD stated:

> The Navigant study and the forthcoming Cal ISO study, which will no doubt repudiate most, if not all, of Navigant's work, are a waste of time, money and effort. A prediction of how many tariff amendments the Cal ISO will file over the next twenty years would be more certain than anyone's prediction of the Cal ISO costs just two years from now.

The TID commented:

> Western should not be persuaded to forego the FCA [Federal Control Area] option because some indicate that it *may* not be the low cost option. If, as the CAISO, and perhaps others, purport, participating in the CAISO is the most cost effective approach, then over time, Western customers will migrate to the CAISO market. The CAISO has a mission of being the preferred transmission provider. If they meet the goal, Western customers will find ways to participate and join the CAISO.

The ISO and a number of other commentors were concerned that Western has the information it needs to make a fully informed decision, and that the decision recognize and incorporate the needs of all the parties, and not just a small subset of users. Although Western is aware of the issue of impacts to statewide ratepayers, under Reclamation law, Western's legal obligations are to Project Use and Preference Power customers. Western views the Navigant study as a screening study to determine the comparative differences between the alternatives and to determine which alternatives, if any, were significantly more or less cost-effective than the others. The study looked at the cost of delivering power to Federal Base Resource and Custom Product customers to the customers' delivery point(s). Western believes that the study used reasonable assumptions and cost data based on information available at the time. Western analyzed the comments and determined that since the PTO Alternative is the most expensive from the comparative economic benefits perspective, the PTO Alternative almost meets the cost-effectiveness criteria.

Under the terms and conditions of Contract 2948A, PG&E agreed to provide transmission service to Federal Project Use and Preference Power customers instead of the Federal Government constructing its own transmission system. Although this contract contains an expiration date, since PG&E's actions precluded the Federal Government from constructing its own facilities, Western asserts that PG&E is responsible for assuring the delivery of Federal power at rates consistent with its embedded cost of service. Therefore, any cost increases for transmission service beyond those already established under the terms and conditions of Contract 2948A constitute a cost shift to Reclamation's Project Use loads and Western's Preference Power customers. Since PG&E is presently paying these costs, costs to statewide ratepayers would not increase if the current arrangements continue.

Summary Analysis of the PTO Alternative

The PTO Alternative integrates the Federal generation and transmission system with the ISO-controlled grid. Under this alternative, Western's customers would be subject to all of the ISO charges associated with transmission and delivery of Federal power at their delivery points. For off-system Project Use loads and Preference customers, the resulting increase in ISO transmission and related charges would result in a cost shift from the transmission service now provided by PG&E under Contract 2948A. These customers are currently provided transmission service by PG&E for Federal power at embedded cost rates. Western's off-system Project Use and Preference customers would be subject to all of the ISO charges associated with transmission and delivery of Federal power to them. These charges represent a significant increase in costs to off-system Project Use loads and Western's Preference customers. These costs are now being paid to the ISO by PG&E under terms of Contract 2948A but will be charged to off-system Project Use loads and Preference customers after January 1, 2005. Unless successor arrangements can be successfully negotiated with PG&E, and/or other cost allocation arrangements undertaken, these cost shifts are unavoidable not only under the PTO, but also for the MSS, sub-control area, and control area alternatives. Western will consider alternatives to minimize these cost shifts to its customers as part of its formal rate process.

For Project Use loads and Preference customers directly connected to the Federal transmission system, the cost-of-service rates would increase substantially, as transmission access charges would increase from cost-of-service rates associated with Federal transmission facilities to include the cost of statewide transmission. This would result in a significant cost shift to these users without a corresponding increase in service or benefits.

As the SC for Reclamation's generation and for customers who have contracted for this service, Western's overall cost to deliver Federal power to the ISO grid may not significantly increase if it is able to operate to minimize the need to purchase significant amounts of imbalance energy and/or ancillary services under the PTO Alternative. From an infrastructure standpoint, the PTO Alternative will still require development and implementation of all of the systems described previously in the section entitled, ''Implementing the Post-2004 Power Marketing Plan,'' except for the reliability support function portion of the Scheduling system. Implementing the PTO Alternative would eliminate the need for a scheduling system to support the reliability function. However, additional programming would be required to assure that data would be appropriately collected and shared between Western's Power Marketing and Power Operations functions and the ISO.

From a staffing standpoint, Western would have to maintain a 24-hour Merchant Desk and a 24-hour Transmission Switching Desk, requiring an estimated 15 positions. The Transmission Switching Desk already exists. Western intends to hire the Merchant Desk positions from within the organization to the maximum extent possible to minimize the need for new staff and to continue transforming its organization to meet the needs of its new Marketing Plan. In addition, Western may need to add staff to the Settlements function to reconcile ISO charges and issue bills to customers for SC services provided to some of the customers as charged by the ISO to

Western. Under the PTO alternative, the intent is to use existing staff to the maximum extent possible.

This table summarizes the relative ratings of each evaluation criteria for the PTO Alternative:

PTO ALTERNATIVE EVALUATION SUMMARY

Evaluation factors	Meets	Almost meets	Does not meet
Flexibility	XX		
Certainty			XX
Durability		XX	
Operating Transparency	XX		
Cost-Effectiveness		XX	

The Metered Subsystem Alternative

The ISO defines an MSS as the system of a transmission owner bounded by ISO-certified revenue quality meters at each interface point and generating units internal to that metered system. Upon execution of an MSS agreement or an MSS aggregator agreement with the ISO, the agreement would establish Western's transmission system boundaries and identify which direct and non-direct connected entities would be included within Western's MSS. Western would remain responsible for operating, maintaining, and replacing the CVP transmission facilities. Reclamation would not be required to execute a PGA with the ISO. Reclamation would remain responsible for switching, maintaining, and replacing the CVP's generating facilities.

Under this alternative, Western could operate as a sub-control area within the ISO control area and would be responsible for scheduling the use of the CVP transmission system and Western's Malin-Round Mountain transmission line. Assuming that Western remained as the COTP operating agent, this line would also be under the operational control of Western, with Western continuing to be responsible for maintenance and replacement of these facilities. Western would have the scheduling responsibility for use of the CVP transmission system, the COTP, and the Malin-Round Mountain transmission line. The ISO would remain as the single path operator for the entire COI.

Operating Scenario To Evaluate the MSS Alternative

Under the MSS Alternative, Western would have a physically defined contiguous system that includes those customers wishing to participate. Although the ISO allows off-system loads to be aggregated together and incorporated into an aggregated MSS, because of possible resource constraints associated with following the loads of individual participants, Western would need to retain operational flexibility over the ultimate size of the MSS and the timing of when new participants would be added. Initially, Western would limit the size of the MSS to First Preference, Project Use loads, and direct-connected Preference Power customers wishing to participate. Other Preference Power customers may be added, as Western gains operational experience. The aggregated MSS would be similar in concept to dynamic scheduling from one control area to another. Western's system would be integrated within the ISO control area, but Western would manage the net power flows through the interconnection points with the ISO. Western would be responsible for scheduling energy deliveries to Project Use load, First Preference customers, and other Preference customers within the MSS. For customers not participating in the MSS, Western would schedule deliveries with the ISO under generation schedules developed by Reclamation and Western.

Western could self-provide imbalance energy and ancillary services to the MSS and could participate fully within the ISO markets if excess generation or reserves were available. Under the MSS Alternative, Western would operate the contiguous Federal system as a sub-control area within the ISO control area. Off-system customers that are participants in Western's MSS would be included, from an accounting standpoint, as if they were inside that sub-control area, in a similar fashion to Western dynamically scheduling to off-system participants. Under the MSS Alternative, the aggregated MSS net scheduled interchange with the ISO would be followed on a 10-minute basis (or possibly 5-minute basis) by Western. The imbalance energy provided by the ISO would be determined as the deviation from net scheduled interchange of the aggregated MSS participants, integrated over a 10-minute period (or 5-minute period). This is different from dynamic scheduling in that Western would follow deviations from net scheduled interchange on a 4-second basis.

Western would pay all the ISO charges associated with the aggregated net flows into the MSS. Off-system Project Use loads and Preference customers participating in the MSS would also be charged for use of the ISO grid. Western's customers directly connected to Western would not be subject to charges for use of the ISO grid to deliver Federal power. However, off-system Project Use loads and Preference customers would incur all of the ISO transmission and related charges associated with the net energy deliveries to the MSS. Western would market transmission service to its customers in a similar fashion as is done today.

From an operational perspective, Western would have a 24-hour Merchant Desk to purchase energy required for Western's Variable Resource and Full Load Service customers and would be the SC for those customers. The 24-hour staffing of the Merchant Desk is required by the ISO for Western to maintain SC status. Western would also have to maintain a 24-hour Switching Desk to perform switching for outages of system elements (such as transmission lines and breakers) for maintenance, repair, or replacement, or to assist the ISO in restoring the system following a disturbance. Since Western would be scheduling the use of its transmission system and those elements of the COI it owns or is responsible for under contract, Western would maintain a 24-hour Transmission Scheduling Desk. Western would also maintain a 24-hour AGC Desk to self-provide ancillary services and to minimize imbalance energy purchases.

From an organizational perspective, Western would continue to need a power accounting, billing, and settlements function to account for services purchased and sold, reconcile billings from the ISO and others to the accounting records, and issue invoices to Western's customers and the ISO. Western would also perform the accounting and settlements function for the MSS, as aggregated, to reconcile the services purchased and delivered to individual MSS members. This could require the addition of settlements staff above current levels.

Evaluation of the Flexibility Criteria Under the MSS Alternative

Implementing the MSS Alternative, like the PTO Alternative, would subject Western to the terms and conditions of the ISO Tariff. Notwithstanding a contractual agreement, Western would need to conform its business practices every time the ISO Tariff is revised. If a new RTO is established and the ISO chooses to join, any changes that the ISO would need to make to its existing operating and business protocols would also need to be made by Reclamation and Western. Western would either comply with any changes required within the time frame required by the ISO or choose to terminate the MSS agreement. Because of the 6-month notice requirement, the effective date of the termination is not immediate. In the interim, as an MSS, Western and Reclamation would need to conform their business practices to the extent not precluded by Federal law.

If the ISO is certified by the Commission as an RTO, any changes that the ISO would need to make as a result of its new role would presumably be incorporated in its tariff. Western could choose to either undertake the necessary changes in its business processes or choose to terminate the MSS agreement. As with the PTO Alternative, because of a specific notice requirement (several existing MSS agreements have a 6-month termination notice requirement) the effective date of the termination is not immediate. In the interim, as an MSS, Western and Reclamation would need to conform their business practices to the extent not precluded by Federal law.

Since Reclamation is not required to sign a PGA under the MSS agreement, to the extent that Reclamation chooses not to be party to Western's MSS agreement, potential concerns may arise from liability that Western could incur from the lack of a contractual relationship between the ISO and Reclamation. For example, as the control area operator, the ISO could direct that certain generators undertake specific actions. To the extent that such actions are inconsistent with the project authorization for the CVP, or other Federal law or regulation, Western would need to negotiate exceptions to take care of Federal legal and jurisdictional issues. The specific terms and conditions relating to the ISO's operational jurisdiction over Federally-owned generation and transmission facilities would need to be carefully evaluated to assure that, as the result of implementing this alternative, the authorized project purposes of the CVP would not be impaired.

Because the MSS Alternative specifically requires Western to define its physical boundaries, it provides future flexibility to move its system intact to another control area or an RTO. While Western is under an MSS arrangement, any operating changes necessitated by NERC and WECC would presumably be translated into ISO Tariff revisions or operational protocol changes.

Since Western would have its boundaries formed under the MSS Alternative, Western believes that this alternative provides for short-term and long-term flexibility, restricted only by the termination provisions of the MSS agreement. However, the MSS Alternative could create business uncertainty and unforeseen impacts for off-system Western customers should Western decide it would need to terminate its MSS agreement. Since the MSS participant continues to retain its ability to provide a notice to terminate the MSS agreement at its discretion, Western concludes that this option meets the flexibility criteria.

Evaluation of the Certainty Criteria Under the MSS Alternative

The MSS Alternative provides participants the ability to avoid some ISO charges because the ISO will base its charges on net flows into the MSS, not gross flows as under the PTO option. The ISO indicated charges for power deliveries to off-system customers would be based on "cost causation" principles that would recover the cost for providing the product or service. Western interpreted this statement to mean that individual customers would be charged for power deliveries based on their use of the ISO grid. Some commentors have raised questions related to the meaning of "cost causation." For instance, the TPUD commented:

> During the July 30 hearing, the Cal ISO's use of the term "cost causation" was illustrative of their mind set. This term should not be confused with "cost based" as it seemed the Cal ISO wanted to imply. Cost based charges are based on the cost to provide a service. "Cost causation" is an attempt to appropriately divvy up whatever charges a particular provider can get away with under whatever the "Market" rules are at the time.

The TID commented on the cost basis for rates under a Federal control area and said:

> Under an alternative CAISO approach, the cost of transmission from generation to load will be set by a market that cannot be forecast with any certainty. Although there may be ways to partially hedge the uncertainty, there are costs associated with the hedges and hedges are not perfect.

The ISO is in the midst of implementing new operating guidance for its MD02 initiative. The proposed new initiative would implement the concept of locational marginal pricing as a means to deal with congestion of transmission pathways. If MD02 is implemented in its current format during periods of congestion, the ISO would re-dispatch all generation based on economic factors. Under this alternative, affected CVP Preference Power customers and the Project Use loads could end up paying a different price than the actual cost-of-service rates associated with Federal hydropower resources. These rates may not be consistent with Reclamation law and policy and Western may need to consider mitigation strategies. Unlike the PTO Alternative, where all CVP Preference Power customers are potentially impacted, under this alternative, those Preference Power customers and Project Use loads, which are contained within Western's interconnected generation and transmission system (known as the bubble), may be able to mitigate some of these impacts.

Under the MSS Alternative, Western and its customers would avoid certain ISO charges. Although Western views the MSS Alternative as providing some relief from ISO charges, to the extent that some of these charges continue to be market-based and subject to changes from tariff amendments, the MSS Alternative continues to present business risk and uncertainty. Notwithstanding a contractual agreement, Western would need to conform its business practices every time the ISO Tariff is revised. Although the MSS Alternative provides some relief from costs, to the extent that the charges are subject to potential ISO Tariff revisions and the differential MD02 impacts between the direct and non-direct connected Preference Power and Project Use loads, Western determined that this alternative almost meets the certainty criteria.

Evaluation of the Durability Criteria Under the MSS Alternative

In general, operating business protocols and practices are established and defined by the agreements which create the relationship. These agreements establish obligations and responsibilities of the parties and allocate the burdens and benefits of each business relationship. In a contractual relationship, these practices and procedures are established for the duration of the agreement and normally allow the parties to modify parts of the agreement over time to properly account for any significant changes in the benefits and burdens that may be experienced by either party.

Under the MSS option, although the relationship between Western and the ISO will be based upon an agreement entered into between the parties, because the ISO's business operating protocols and procedures are tariff based, and not contract-based, the terms, conditions, rates, and other pertinent aspects of interacting with the ISO can be changed through new ISO Tariff amendments. Notwithstanding a contractual agreement, Western would need to conform its business practices every time the ISO Tariff is revised. In the event Western and the ISO cannot agree upon potential changes to its existing agreement(s), the ISO can submit its proposed changes to the Commission for resolution.

Many of the commentors in this public process expressed concerns with the long-term durability of any arrangement with the ISO because the agreement would be tariff-based. Many of the comments equated stable, long-term business relationships as occurring through contract-based and not tariff-based relationships.

For instance, the TANC stated:

> We believe in the durability of long-term contracts for establishing rights and obligations of load serving entities. Western has always utilized this approach to doing business. The CAISO has historically attempted to alter the rights and obligations of existing contracts. The CAISO utilizes tariffs that can and have been frequently changed. The CAISO files amendments too frequently to consider the CAISO Tariff durable or predictable.

Others such as the MID, the TID, and the SVP cite the 55 amendments filed by the ISO at the Commission in the last 5 years as evidence that a relationship with the ISO is not durable.

The ISO commented:

> The ISO's operating protocols have remained substantially the same since the ISO start-up date in 1998. The only changes in operating protocols are based on the need to comply with changing operational criteria from the NERC and WECC. However, every control area, including the Western Control Area, would have to make similar changes over time. Admittedly, the ISO has necessarily changed the protocols associated with markets, market implementation and market rules a number of times over the past 6 years. Given that the ISO was the first of its kind in the United States, an evolutionary process has been necessary when it comes to markets. Thus Western's concern with durability with respect to operating protocols has been met, but market durability is still evolving and will continue to evolve for a number of years to come. Western cannot disguise its concern regarding ''operating protocol durability'' as an off-hand reference to the energy crisis and changing market rules. Moreover, the ISO's ongoing market modifications are designed to promote stability based on experience, best practices, and coordination of operations to the benefit of all California consumers and market participants.

From a durability standpoint, the MSS Alternative is only as durable as the ISO Tariff is over time. Fifty-seven ISO Tariff amendments have been filed since the ISO became operational in 1998. Western notes the ISO has filed four tariff amendments since this public process began on June 24, 2003. Notwithstanding a contractual agreement, Western would need to conform its business practices every time the ISO Tariff is revised. Although it is important to distinguish between procedural and substantive changes to the ISO Tariff, the underlying ability of the ISO to undertake changes to its business and operating protocols and procedures creates business uncertainty and risk.

Based on the affected term or condition, these changes can materially affect the relationship between the benefits and burdens that each party would receive and impart as a result of being an MSS. Stakeholders continue to have ongoing concerns related to the frequency and number of amendments to the ISO Tariff. Although many of these changes would parallel changes that other control area operators must implement in response to ongoing industry changes, because of their frequency and the number of substantive changes, Western concludes that the PTO Alternative almost meets the durability criteria.

Evaluation of the Operating Transparency Criteria Under the MSS Alternative

Under the MSS Alternative, Western would operate its system as a sub-control area within the ISO control area. Western would dispatch the internal generation of Reclamation, as needed, to satisfy the needs of the sub-control area and to maintain the net scheduled interchange with the ISO. Western would schedule the use of its transmission system to meet its statutory obligations to Project Use loads and contractual obligations to its customers as well as to meet the needs of the sub-control area and MSS participants in aggregate. Operation of the Federal system would not be a concern to the ISO as long as Western maintains its scheduled flows with the ISO.

Scheduling the use of Western's ownership in the Malin-Round Mountain transmission line and the COTP would remain Western's responsibility and would be performed under NERC and WECC protocols and operating procedures developed by the Bonneville Power Administration (BPA), the ISO, Western, and others. Under the MSS Alternative, and unless otherwise desired, the ISO would continue to remain the single path operator for the COI south of the California-Oregon Border (COB).

Because operation of the Federal system would have to meet the terms of the MSS agreement and operating procedures for the COI developed under NERC and WECC operating criteria, Western would not be able to change the operation of the Federal system unilaterally. Western acknowledges that changes in the operation of the Federal system would have to be structured to assure that unintended impacts to third parties do not occur. Because of these considerations, Western concludes that the MSS Alternative meets the operational transparency criteria.

Evaluation of the Cost-Effectiveness Criteria Under the MSS Alternative

Navigant prepared a revised comparative economic benefit analysis for each post-2004 operational alternative considered on behalf of Reclamation and Western incorporating comments received from the ISO and others related to the underlying assumptions used in the study. The revised study shows that, comparatively, the cost of the MSS and control area alternatives remain similar and that the PTO option continues to be the least cost-effective of the three post-2004 alternatives being considered.

Commentors during the public process expressed their views about the comparative economic study performed by Navigant and the importance of the cost effectiveness criteria.

The TANC commented:

> * * * given the rapid escalation of the CAISO costs, numerous inaccuracies of CAISO settlements, and extreme complexity and variability of CAISO market design, assumption-based cost forecasts in the CAISO environment are difficult to estimate and cannot be the most important evaluation criteria for Western and its Customers.

The TPUD stated:

> The Navigant study and the forthcoming Cal ISO study, which will no doubt repudiate most, if not all, of Navigant's work, are a waste of time, money and effort. A prediction of how many tariff amendments the Cal ISO will file over the next twenty years would be more certain than anyone's prediction of the Cal ISO costs just two years from now.

The TID commented:

> Western should not be persuaded to forego the FCA [Federal Control Area] option because some indicate that it *may* not be the low cost option. If, as the CAISO, and perhaps others, purport, participating in the CAISO is the most cost effective approach, then over time, Western customers will migrate to the CAISO market. The CAISO has a mission of being the preferred transmission provider. If they meet the goal, Western customers will find ways to participate and join the CAISO.

A number of Western's customers were especially concerned about increases in their internal costs associated with meeting the billing and settlements requirements associated with participating in the ISO markets. Increased complexity and the need for additional investment in software and other associated equipment and infrastructure, as well as additional staff to handle ISO business requirements, are all concerns.

Western views the Navigant study as what it was intended to be; a screening study to determine if any one of the alternatives were more or less cost-effective than the other alternatives. The revised comparative economic studies containing updated assumptions, referenced above, continue to indicate that the MSS and Control Area alternatives are comparable. Western, therefore, concludes that the MSS Alternative meets the cost-effectiveness criteria.

Under the terms and conditions of Contract 2948A, PG&E agreed to provide transmission service to Federal Project Use loads and Preference customers instead of the Federal Government constructing its own transmission system. Although this contract expires, since PG&E's actions precluded the Federal Government from constructing its own facilities, Western asserts that PG&E is responsible for assuring the delivery of Federal power at rates consistent with its embedded cost of service. Any cost increases for transmission service beyond those already established under the terms and conditions of Contract 2948A constitute a cost-shift to Reclamation's Project Use loads and Western's Preference customers. Since PG&E is now paying those costs, costs to statewide ratepayers would not increase if the current arrangement continues.

Summary Analysis of the MSS Alternative

The MSS Alternative includes operation of the Federal system as a sub-control area within the ISO control area and provides, through accounting mechanisms with the ISO, for Western to follow the loads of Western's MSS participants. Through the ''net'' settlements treatment of the MSS by the ISO, some of the ISO charges for imbalance energy and reserves could be avoided by MSS participants. However, off-system Project Use loads and Preference customers would still be subject to transmission and related charges by the ISO. With the expiration of Contract 2948A, the expenses previously paid by PG&E would be shifted to off-system customers. These customers would see a significant increase in their costs for transmission service.

Western's off-system Project Use loads and Preference customers would be subject to all of the ISO charges associated with transmission and delivery of Federal power to them. These charges represent a significant increase in costs to Western's off-system customers. Under Contract 2948A, PG&E has an obligation to serve the combined PG&E/Western load under the terms and conditions of the contract. These costs are now being paid to the ISO by PG&E under terms of Contract 2948A but will be charged to Western's off-system customers after January 1, 2005. The ''net'' settlement treatment, if these Project Use loads and Preference customers are MSS participants, may reduce the total cost impact but some cost shifting will occur. Unless successor arrangements can be successfully negotiated with PG&E, and/or other cost allocation arrangements undertaken, these cost shifts are unavoidable under the PTO, MSS, sub-control area, and control area alternatives. As part of its formal rate process, Western is considering alternatives to minimize these cost shifts to its customers.

From an infrastructure standpoint, the MSS Alternative will still require the development and implementation of all of the systems described previously in the section entitled, ''Implementing the post-2004 Power Marketing Plan.'' In addition to these systems, Western will have to upgrade its Supervisory Control and Data Acquisition (SCADA) system to include an AGC module. From a staffing standpoint, Western would have to maintain a 24-hour Merchant Desk and a 24-hour Transmission Switching Desk, requiring an estimated 15 positions. The Transmission Switching Desk already exists. Western intends to hire the Merchant Desk positions from within the organization to the maximum extent possible to minimize the need for new staff and to continue transforming its organization to meet the needs of its new Marketing Plan. Western would have to maintain a 24-hour AGC desk and a 24-hour Transmission Scheduling and Security Desk requiring another estimated 14 positions. Because of the existing staffing levels, Western anticipates that it will need to hire only eight new positions to staff these three desks (AGC, Transmission Scheduling, and Transmission Security) above what is required for the PTO Alternative. Western may also need to add additional staff to the Settlements function to account for and reconcile ISO and Western charges and issue bills to MSS participants for services provided in following load and providing reserves for MSS participants. Western estimates it will need an additional two positions to accommodate these activities.

This table summarizes the relative ratings of each evaluation criteria for the MSS Alternative:

MSS ALTERNATIVE EVALUATION SUMMARY

Evaluation factors	Meets	Almost meets	Does not meet
Flexibility	XX		
Certainty	....	XX	
Durability	....	XX	
Operating Transparency	XX		
Cost-Effectiveness	XX		

The Control Area Alternative

Under this alternative, Western would initiate the control area certification process by submitting an application to NERC and WECC. This process requires up to 6 months to complete and requires Western to document its ability to operate its system reliably under all applicable NERC and WECC policies and guidelines. In addition, Western must demonstrate its operations will not affect neighboring control areas. In the event impacts to neighboring control areas are identified, Western must identify and implement sufficient remedial measures to mitigate such impacts.

Once an application is submitted, a review team is selected from the WECC membership. The review process includes interviews and/or questionnaires of neighboring control areas. This process is designed to identify issues that may arise from Western forming a control area. Any issues that are identified during the review process must be resolved to the satisfaction of WECC before a new control area is certified. When the review team is satisfied that Western can operate its system reliably within applicable NERC and WECC criteria, the review team will recommend to the NERC and WECC Boards of Directors that certification status be approved. Western would receive certification to operate as a control area only when the review team's recommendation is approved by the NERC and WECC Boards of Directors.

Under this alternative, Western would continue to be responsible for operating, maintaining, and replacing the CVP transmission facilities. Reclamation would remain responsible for switching, maintaining, and replacing the CVP generating facilities. Under this alternative, Western would operate as a control area and establish control area boundaries with the ISO, the BPA, and

SMUD. Western would schedule the use of the CVP transmission system and Western's Malin-Round Mountain transmission line. If Western continues in its roles as the operating agent for COTP, this line would also be included within the Western control area and Western would assume responsibility for its operational control. As long as it continues as COTP's operating agent, Western would continue to provide services to maintain and replace these facilities. Western would schedule use of the CVP transmission system, the COTP, and the Malin-Round Mountain transmission line. The ISO would remain as the single path operator for the entire COI.

Operating Scenario To Evaluate the Control Area Alternative

Under the Control Area Alternative, Western would establish a physically defined contiguous system. As a control area operator, Western would manage the net power flows through its interconnection points with the ISO, BPA, and SMUD under NERC and WECC criteria and guidelines. Western would schedule energy deliveries to Project Use load, First Preference customers, and other customers, match its generation and load, provide reserves, and provide frequency support for the WECC interconnection under NERC and WECC criteria and generation schedules developed by Reclamation and Western.

Western would self-provide imbalance energy and ancillary services and could participate in the ISO markets whenever excess generation or reserves are available. Although off-system customers would not be included in the initial control area formation phase, Western contemplates discussing the possibility of dynamically scheduling to off-system customers with the ISO after sufficient experience is gained as a control area operator and the ability of Reclamation's generation to follow loads dynamically is ascertained.

Western's customers directly connected to Western's system would not be subject to use of the ISO grid for deliveries of Federal power. However, off-system Project Use loads and Preference customers would incur all of the ISO transmission and related charges associated with the deliveries of Federal power. Western would market transmission service to its customers on an open access and non-discriminatory basis.

From an operational perspective, Western would have a 24-hour Merchant Desk to purchase energy required for Western's Variable Resource and Full Load Service customers and would act as the SC for Reclamation's generation and Project Use loads, as well as for interested customers. The 24-hour staffing of the Merchant Desk is required by the ISO for Western to maintain its SC status, as well as to implement its post-2004 Marketing Plan. Western would also maintain a 24-hour Switching Desk to perform switching for outages of system elements (such as transmission lines and breakers) for maintenance, repair, or replacement, or to assist the interconnected systems in restoring the system following a disturbance. Since Western would schedule the use of its transmission system and those elements of the COI it owns or is responsible for under contract, Western would have to maintain a 24-hour Transmission Scheduling Desk. To regulate the control area, Western would maintain a 24-hour AGC Desk.

From an organizational perspective, Western would continue to need a power accounting, billing, and settlements function to account for services purchased and sold, reconcile billings from the ISO and others to the accounting records, and issue invoices to Western's customers and the ISO. Current staffing levels in the settlements function would need to increase by an additional two positions to support the additional workload for the Control Area Alternative.

Evaluation of the Flexibility Criteria Under the Control Area Alternative

Under the Control Area Alternative, Western would be required to physically establish its boundaries and become a stand-alone unit within the WECC interconnection. In forming a control area, Western would need to have operational agreements with neighboring control areas to assure it would operate its system in concert with neighboring systems. These arrangements typically include metering and communication agreements, emergency operations procedures, normal operating procedures, data exchange arrangements, and power accounting procedures. These arrangements comply with NERC and WECC standards.

As NERC and WECC industry wide standards change, Western would have to change its procedures and structure its inter-control area agreements to accommodate such industry wide changes. Therefore, short-term flexibility would be provided for within the construct of the inter-control area agreements.

When, and if, Western chooses to join an RTO, it could do so as a stand-alone entity, without the need to terminate any agreement. The operating agreements between Western and the neighboring control areas would not change, because from a physical standpoint, nothing changes if Western joins an RTO. Operational protocols may change, but the physical operation of the system must continue. Changes in operational protocols would still have to comply with the applicable NERC and WECC reliability standards.

Because of the absence of the need to terminate any agreement, and the intended construct of the inter-control area agreements with neighboring control areas, Western concludes the Control Area Alternative meets the flexibility criteria.

Evaluation of the Certainty Criteria Under the Control Area Alternative

Under the Control Area Alternative, neither Western nor the direct-connected customers would be subject to ISO charges except for those services purchased from the ISO. Western, however, would charge the direct-connected customers for capacity, energy, transmission, and ancillary services with rates determined through a public process. Western's off-system Project Use loads and Preference customers would be subject to ISO charges for transmission and delivery of Federal power and ancillary services. Under this alternative, Western intends to implement dynamic scheduling after it has sufficient experience operating as a control area. Consequently, non-direct connected customers may be able to avoid some of the imbalance energy and reserve charges of the ISO shortly after the control area is established and operational.

Costs associated with the Control Area Alternative are expected to be fairly predictable and include charges for labor and equipment to operate, maintain, and replace the CVP transmission facilities of Western and the costs allocated to hydropower generation facilities owned and operated by Reclamation. These costs have historically been included in CVP power rates established by Western. CVP rates are cost based and established at the lowest possible rates consistent with sound business principles. Additional costs associated with operating a control area are purchased power costs necessary to balance the control area during the fall and winter months when insufficient generation is available to meet Project Use and First Preference loads. Power purchased for these purposes is expected to be purchased in the forward markets as blocks, rather than purchased on the spot market, to reduce price volatility and ensure stable rates. With the ongoing development of generation optimization tools, Western expects the timing and quantity of purchased power amounts can be predicted with reasonable certainty after Contract 2948A expires.

Using the forward purchase approach, the Control Area Alternative should limit Western's exposure to the spot market. Because the preponderance of Western's costs are within Western's control, CVP rates should remain reasonably stable over time, and rate adjustments should not be needed more often than that which has historically occurred, approximately every 3 years. As a control area, Western would be required to meet WECC and NERC operating criteria. To the extent Western is not able to fully comply with such criteria, it will be subject to financial penalties for non-compliance. Western has considered this risk in its decision-making process.

The ISO is in the midst of implementing new operating guidance for its MD02 initiative. This new initiative would implement the concept of locational marginal pricing to deal with transmission congestion. If MD02 is implemented in its current format during congestion periods, the ISO would re-dispatch all generation based on economic factors. Under this alternative, CVP Preference customers and Project Use loads that remain in the ISO control area could end up paying a different price than the cost-of-service rates associated with Federal hydropower resources. These rates may not be consistent with Reclamation law and policy and Western may need to consider mitigation strategies. Western concludes that for control area participants, the Control Area Alternative meets the certainty criteria.

In addition to implementing a new control area, Western is also considering the possibility of assessing charges on the PACI associated with the cost of off-system deliveries to its customers served via the ISO-controlled grid. The intent of Congress, when it authorized the construction of the PACI, was to assure that Federal Preference customers would receive power as if Federal facilities had been constructed. Although this cost would in effect result in rate pancaking users of the PACI, Western believes these costs are relatively minor and assures that the intent of Congress continues to be met. These costs are outside the scope of this process and will be discussed as part of the rate process for implementation of the post-2004 Marketing Plan and the post-2004 Operational Alternative, which is scheduled to start February 2004.

Evaluation of the Durability Criteria Under the Control Area Alternative

Under the Control Area Alternative, Western would be subject to industry wide changes in operating protocols and business practices coordinated by NERC and WECC. These changes generally result from policy or standards changes made through industry consensus and approved by the NERC and WECC Boards of Directors and, historically, have not occurred with great frequency.

Changes in Western's business practices are generally determined by changes in Federal or industry wide policies and may be made through a public process designed to assure that the impacts of these changes are fully understood by the agency prior to implementing them. Western contemplates executing contracts with intra-control area participants. These contracts would recognize physical rights and should assure reasonable predictability and allow the participants to manage their risks and make the appropriate long-term business decisions. Because the operating protocols and business practices under the Control Area Alternative are controlled by industry consensus or Western's own actions, Western concludes that the Control Area Alternative meets the durability criteria.

Evaluation of the Operating Transparency Criteria Under the Control Area Alternative

To become a certified control area, Western would have to operate under NERC and WECC operating criteria and guidelines. These criteria and guidelines require that the operation of Western's system cannot impact other control areas. If Western were to change the operation of the Federal system, as a control area, it would have to assure such changes would not impact third parties or its operation would not violate NERC and WECC requirements and consequently be subject to financial penalties under the WECC Reliability Management System agreement. Because of the requirements within NERC and WECC criteria and guidelines to assure no impacts on third parties occur as a result of Western's control area operations, Western concludes that the Control Area Alternative meets the operating transparency criteria.

Evaluation of the Cost-Effectiveness Criteria Under the Control Area Alternative

Western is considering the possibility of assessing charges on the PACI associated with the cost of off-system deliveries to its Project Use loads and Preference customers served via the ISO-controlled grid. The intent of Congress, when it authorized the construction of the PACI, was to assure that Federal Project Use loads and Preference customers would receive power as if Federal facilities had been constructed. Although this cost would in effect result in rate pancaking for PACI users, Western believes these costs are relatively minor and assures the intent of Congress continues to be met. These costs are outside the scope of this process and will be discussed as part of the rate process for implementation of the post-2004 Marketing Plan and the post-2004 Operational Alternative, which is scheduled to start February 2004.

Navigant prepared a revised comparative economic benefit analysis for each post-2004 operational alternative, which incorporated comments received from the ISO and others related to the underlying assumptions used in the study. The revised study shows that, comparatively, the relative cost of the MSS and Control Area alternatives remain similar. The PTO option continues to be the least desirable from a cost standpoint of the three post-2004 alternatives under consideration.

Western reviewed the comments on the Navigant study referenced above provided by the ISO and others and made a number of changes to the study which are described in the section entitled ''Comparative Economic Benefits Study.'' The revised study continues to indicate that the MSS and Control Area alternatives are comparable.

During the public process, commentors offered some views relative to the economic studies performed by Navigant and the importance of the cost effectiveness criteria.

The TANC commented:

> * * * given the rapid escalation of the CAISO costs, numerous inaccuracies of CAISO settlements, and extreme complexity and variability of CAISO market design, assumption-based cost forecasts in the CAISO environment are difficult to estimate and cannot be the most important evaluation criteria for Western and its customers.

The TPUD stated:

> The Navigant study and the forthcoming Cal ISO study, which will no doubt repudiate most, if not all, of Navigant's work, are a waste of time, money and effort. A prediction of how many tariff amendments the Cal ISO will file over the next twenty years would be more certain than anyone's prediction of the Cal ISO costs just two years from now.

The TID commented:

> Western should not be persuaded to forego the FCA [Federal Control Area] option because some indicate that it *may* not be the low cost option. If, as the CAISO, and perhaps others, purport, participating in the CAISO is the most cost effective approach, then over time, Western customers will migrate to the CAISO market. The CAISO has a mission of being the preferred transmission provider. If they meet the goal, Western customers will find ways to participate and join the CAISO.

The ISO and a number of other commentors expressed concern that Western has the information it needs to make a fully informed decision, and that the decision recognize and incorporate the needs of all the parties, and not just a small subset. Western views the Navigant study as a screening study to determine the comparative differences between the alternatives and to determine which alternatives, if any, are clearly better or worse than the others. The study looked at the cost of delivering Federal Base Resource to Variable Resource customers, and Federal Base Resource and Custom Product power for Full Load Service customers to the customers' delivery point(s). Western believes that the study used reasonable assumptions and cost data based on information available at the time. As a comparative benefit study, the results were never intended to be used to identify and allocate cost repayment responsibilities. Western is undertaking a separate rate process to support the post-2004 operations alternative. The rate process is the appropriate forum to discuss cost allocation and financial repayment obligations. Western has analyzed the comments and determined that the Control Area Alternative meets the cost-effectiveness criteria.

Under the terms and conditions of Contract 2948A, PG&E agreed to provide transmission service to Federal Project Use and Preference customers instead of the Federal Government constructing its own transmission system. Although this contract expires, since PG&E's actions precluded the Federal Government from constructing its own facilities, Western asserts that PG&E is responsible for assuring the delivery of Federal power at rates consistent with its embedded cost of service. Therefore, any cost increases for transmission service beyond those already established under the terms and conditions of Contract 2948A constitute a cost-shift to Project Use loads and Preference customers. Since PG&E is now paying those costs, costs to statewide ratepayers would not increase if the current arrangements continue.

Summary Analysis of the Control Area Alternative

Implementing the Control Area Alternative would allow the Federal transmission system to be operated as a NERC and WECC certified control area. Customers directly connected to Western's system would avoid ISO charges for transmission and related services but would incur similar charges from Western. Off-system Project Use loads and Preference customers would, however, incur ISO transmission and related charges. This would represent a cost shift from the transmission service presently provided to off-system Project Use loads and Preference customers under Contract 2948A. As discussed under the PTO option, these customers are currently provided such transmission service by PG&E for Federal power at embedded cost rates. Off-system Project Use loads and Preference customers would be subject to all of the ISO charges associated with transmission and delivery of Federal power to them. These charges represent a significant increase in costs to off-system Project Use loads and Preference customers. These costs are now being paid to the ISO by PG&E currently under terms of Contract 2948A but will be charged to Western's off-system customers after January 1, 2005. Unless successor arrangements can be successfully negotiated with PG&E, and/or other cost allocation arrangements undertaken, these cost shifts are unavoidable under the PTO, MSS, sub-control area, and control area alternatives. As part of its formal rate process, Western is considering alternatives to minimize these cost shifts to Project Use loads and Preference customers.

From an infrastructure standpoint, the Control Area Alternative would still require the development and implementation of all of the systems described earlier in the section entitled, ''Implementing the post-2004 Power Marketing Plan.'' In addition to these systems, Western would have to upgrade its SCADA system to include an AGC module. From a staffing standpoint, Western would have to maintain a 24-hour Merchant Desk and a 24-hour Transmission Switching Desk. This requires an estimated 15 positions. The Transmission Switching Desk already exists. Western intends to hire the Merchant Desk positions from within the organization to the maximum extent possible to minimize the need for new staff and to continue transforming its organization to meet the needs of its new Marketing Plan. Western would have to maintain a 24-hour AGC desk and a 24-hour Transmission Scheduling and Security Desk requiring another estimated 14 positions. Because of existing staffing levels, Western anticipates that it will need to hire only eight new positions to staff these three desks (AGC, Transmission Switching, and Transmission Security) above what is required for the PTO Alternative. Staffing within the settlements function to account for, reconcile ISO and Western charges, and issue bills to customers is expected to increase by two additional positions.

The comparative economics of the Control Area Alternative are described above in the analysis of the PTO Alternative and will not be repeated here. That discussion showed that the Control Area Alternative is comparable to the MSS Alternative.

The relative ratings for the Control Area are summarized:

CONTROL AREA ALTERNATIVE EVALUATION SUMMARY

Evaluation factors	Meets	Almost meets	Does not meet
Flexibility	XX		
Certainty	XX		
Durability	XX		
Operating Transparency	XX		
Cost-Effectiveness	XX		

Other Operational Alternatives

A number of commentors recommended Western consider the possibility of integrating its operations within an already established WECC certified control area such as SMUD. Commentors suggested that such an alternative would be similar in concept to the ISO's MSS template, except the arrangement would be contract-based, and not tariff-based. Western discussed the possibility of a contract-based sub-control area with SMUD. SMUD indicated an interest in pursuing additional discussions. As part of Western's proposed decision, Western will continue discussions with SMUD on forming a contract-based sub-control area. Reclamation, as well as the City of Palo Alto, suggested that Western consider approaching the ISO to ask about the possibility of getting a contract-based sub-control area agreement.

Sufficient detailed information is not now available to make a fully informed judgment to determine how the evaluation criteria would apply to this specific alternative and the relative benefits and burdens associated with its implementation. Western intends to approach the ISO and SMUD to initiate discussions and collect additional data to determine the feasibility of this alternative. If either alternative is feasible, Western will then initiate the appropriate steps to implement it. As part of an initial overall review, the following general statements can be made.

From a flexibility viewpoint, the analysis of a contract-based sub-control area would be similar to the analysis for the MSS Alternative. Flexibility would be limited to the termination provisions of the agreement putting this alternative in place. Therefore, this alternative would probably satisfy the flexibility criteria.

From a certainty viewpoint, the rates and charges for products and services purchased from either control area operator are assumed to be contract- and cost-based, rather than market- and tariff-based. Therefore, rates should be generally stable and predictable. From that perspective, this alternative would probably meet the certainty criteria.

Since this alternative is contingent upon executing a contract-based agreement, and not dependent on changes to a tariff, the terms and conditions should be relatively stable and participants should be able to engage and commit to long-range planning activities. This alternative would probably meet the durability criteria.

The operating transparency of an arrangement with either control area under this alternative should be seamless. As a contract-based sub-control area, Western would operate its facilities within a host control area. The host control area must conform its operations to the reliability standards outlined by NERC and WECC. Consequently, any changes in operational protocols and procedures would have to minimize and/or mitigate any impacts and be accomplished in close coordination with neighboring control area operators. This alternative would probably meet the operating transparency criteria.

Insufficient information is available to make a preliminary determination as to the relative cost-effectiveness of this alternative. However, since the SMUD control area operates on a cost-based orientation, we assume that, at a minimum, it probably meets the cost-effectiveness criteria.

A number of commentors suggested that Western consider a contract-based MSS arrangement with the ISO. The ISO currently operates under a tariff-based system. However, consistent with Western's proposed decision, Western intends to initiate discussions with the ISO to investigate the feasibility of pursuing this type of an agreement.

Comparison of the Operational Alternatives

Implementing each alternative under consideration would result in a different operational configuration and would result in a different relationship with the ISO. Each alternative also subjects Western to different staffing levels because of the needs for different functions associated with that alternative.

The No Action Alternative may create a situation where Western is unable to perform under its power contracts and places Western in a position of scrambling to put arrangements in place to operate the Federal system within the ISO control area. Western may also not be able to assure project repayment under this alternative. Western would essentially be a price and service taker without the ability to negotiate favorable terms and conditions because of the impermanent nature of the operational agreements. Western has determined that this is not a preferable alternative.

The PTO Alternative would result in Western's system being integrated with the ISO control area and all of Western's customers being subject to all of the ISO charges for scheduling and delivery of Federal power to their delivery points. Western's transmission revenue requirement would be met, and its staffing levels under this alternative would be the lowest of any of the alternatives. Western's rates would have to be set to cover all of the ISO charges associated with Western's role as the SC for Reclamation generation.

The MSS Alternative would allow Western to operate within the ISO control area as a sub-control area and would provide accounting mechanisms for Western to include all customers desiring to participate in the MSS to be included in the MSS. Western's customers may avoid some ISO ancillary service charges depending on the ability of the CVP generation to follow the combined load of Western's MSS participants. The direct-connected Project Use loads and Preference customers would also be able to avoid some transmission and related charges, but the off-system Project Use loads and Preference customers would not avoid transmission and other ISO charges. The charges for the MSS Alternative may be lower than under the PTO Alternative because of the ''net'' settlements feature of the MSS.

The Control Area Alternative would allow Western to function as an interconnected control area with BPA, the ISO, and SMUD under NERC and WECC criteria and guidelines. Direct-connected customers would avoid all ISO charges associated with delivery of Federal power, but the off-system Project Use loads and Preference customers would not avoid these charges.

From an infrastructure viewpoint, all of the systems necessary to support the post-2004 Marketing Plan are needed and are independent of the alternative chosen. The MSS, control area, or sub-control area alternatives all require the addition of an AGC module to Western's SCADA system. The MSS, control area, and sub-control area options also require the creation of two new 24-hour desks (AGC and the Transmission Scheduling and Security Desks) as well as the addition of two staff positions in the settlements function. These positions would not be required under the PTO option.

During the public comment period, Western received numerous comments from customers and interested stakeholders indicating their respective preferences for, or against, a specific post-2004 operational alternative. A common thread of the comments received from Western's customers encouraged Western to choose an alternative that did not place Western's relationship with the ISO under the ISO Tariff. Reasons cited were the frequency of changes to the ISO Tariff and the costs associated with possible litigation over proposed ISO Tariff modifications.

The PTO option subjects Project Use loads and Preference customers to all ISO charges. While this option requires the least amount of Federal investment in infrastructure and staffing, it subjects all of the Project Use loads and Preference customers to all ISO charges. This substantially increases cost-of-service rates because the relatively low cost of Federal transmission facilities would be blended with higher statewide transmission facility costs under this alternative. This option also raises concerns related to the operation and control over Federal facilities. Specifically, Reclamation and Western would have to assure the operation of CVP water and hydropower facilities would be consistent with the project's statutory authorizations. Based on these factors, Western is removing the PTO option from further consideration.

The MSS option presents some favorable characteristics for Project Use loads, Preference customers, and Western. The ability to provide some ancillary services to Project Use loads and Preference customers that participate in the MSS, subject to the availability of CVP generation, and the ability to pay ISO charges based on the ''net'' settlements feature appear desirable. Western is concerned with the frequent number of amendments to the ISO Tariff. Numerous commentors raised concerns about the number of ISO Tariff amendments during the public comment period. If Western were able to develop a contractual agreement with the ISO which does not specifically reference the ISO Tariff, and if the contractual agreement contained terms and conditions which would not change during the life of the contract, Western would be interested in pursuing such an arrangement. Such an arrangement would recognize the unique legislated purposes and characteristics of the CVP and would maintain an appropriate balance and separation between a State-controlled and Federal entity. A contract-based MSS option structured under these principles, if offered by the ISO, will be considered. The impact of the ISO's MD02 activities will need to be addressed also. If the ISO cannot accommodate such principles, the MSS option will not be considered further.

The control area option meets all of the decision-making criteria outlined by Western. However, operation as a sub-control area within the SMUD control area also appears to meet these criteria. The direct-connected customers would avoid ISO charges for delivery of Federal power and would pay Western or the host control area for ancillary services associated with such delivery. There are two different approaches for sub-control area operations that could provide benefits for Western and the host control area. The first is called integrated operations and would allow Western to operate within the host control area and provide its share of regulation and reserves associated with the combined load of Western and the host control area. Accounting mechanisms would be put in place to account for services rendered. Essentially, this would resemble integrated operation with the host control area. The second arrangement is called segregated operations and would allow Western to provide reserves and regulation associated with its direct-connected customers and firm exports and regulate hourly to a net scheduled interchange quantity with the host control area. This operation resembles interconnected control area operation, but Western would not be accountable to the WECC and NERC.

The SMUD has expressed interest in establishing a sub-control area under a contractual agreement that would contain terms and conditions established for the duration of the contract. Because of the seasonal nature of the CVP generation resource, a contractual approach to either integrated or segregated operation may contain benefits for Project Use loads, Preference customers, and Western. Western will pursue this further with SMUD.

Other Issues Raised During the Public Process

The ISO and a number of other commentors raised the following three additional issues during the public process. The commentors were specifically concerned about the alternative for a new control area and raised the following three issues: (1) Adverse implications to grid reliability and operations, (2) increased complexity of operating the COI, and (3) inconsistency of Western's proposal with existing Federal policy and proposed direction.

Commentors were concerned that the creation of a new control area was inconsistent with existing Federal policy, which would result in additional complexity and could cause the electrical transmission grid to be operated less reliably. Since the proposed decision does not contemplate formation of a new control area at this time, these issues need not be addressed as part of this **Federal Register** notice.

Western's position is that in the event the control area alternative is ever selected, as part of the WECC/NERC control area certification process, many of the operating issues (grid reliability and increased complexity of operations) raised by the commentors would be identified, analyzed, and mitigated, if appropriate, as part of the control area certification process. These issues would normally be handled as a matter of meeting specific technical performance criteria rather than policy.

Conclusion

Western's Proposed Action

Based upon the analysis done with respect to the decision-making factors outlined by Western in the June 24, 2003, **Federal Register** notice and further explained at the July 9, 2003, Public Information Forum, Western proposes to proceed with its effort to establish a contract-based sub-control area within either the ISO or SMUD control area. Western is not proposing to form a new control area at this time. The complexity and uncertainty of implementing a new marketing plan as well as creating a new control area has caused Western to conclude it is not prudent to try accomplishing both tasks simultaneously. To reduce business risk and uncertainty while establishing a new post-2004 operational configuration upon the termination of existing contracts, Western is proposing to operate its Federal transmission facilities within an existing control area. Western will initiate discussions with the ISO and SMUD to implement a contract-based sub-control area. This option is practical and preserves Western's ability to respond flexibly to ongoing changes in the electric utility industry.

Other Considerations

Consistency With Federal Law

Western will evaluate how Federal law will affect each alternative. Western is governed by numerous Federal laws such as the Federal Reclamation Law. The Federal Reclamation Law requires Federal power be sold to Preference customers. Western implements such sales through a Federal marketing plan under the Administrative Procedure Act. The sale of Federal power must not impair the primary purposes of the CVP. The marketing plans have the full force and effect of law. The alternatives must be consistent with Western's obligations under Federal law including Western's Marketing Plan. For instance, if Western were to become a PTO, it is conceivable that situations could arise where Western would be unable to deliver Federal Preference Power to Federal customers even where adequate Federal transmission capability was available to serve the Federal customer. While the ISO Tariff provides a waiver for Federal entities, if a provision of the Tariff conflicts with Federal law, Western must still work out the specific details on a case-by-case basis whenever such conflicts arise.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. Western has determined that this action does not require a regulatory flexibility analysis since it is a rulemaking of particular applicability involving services applicable to public property.

Environmental Compliance

Under the National Environmental Policy Act (NEPA) (42 U.S.C. 4321. *et seq.*), Council on Environmental Quality NEPA implementing regulations (40

CFR 1500–1508), and DOE NEPA implementing regulations (10 CFR 1021), Western completed an environmental impact statement (EIS) on its Energy Planning and Management Program. The Record of Decision was published in the **Federal Register** (60 FR 53181, October 12, 1995).

Western also completed the 2004 Power Marketing Program EIS (2004 EIS), and the Record of Decision was published in the **Federal Register** (62 FR 22934, April 28, 1997). The Marketing Plan falls within the range of alternatives considered in the 2004 EIS. This NEPA review identified and analyzed environmental effects related to the Marketing Plan. Available reservoir storage and water releases controlled by Reclamation influences marketable CVP and Washoe project electrical capacity and energy. Reclamation completed a programmatic Environmental Impact Statement (PEIS) under the CVP Improvement Act of 1992 (Pub. L. 102–575, Title 34) on October 1999. Actions based on the PEIS may result in modifications to CVP facilities and operations that would affect the timing and quantity of electric power generated by the CVP. Such changes may affect electric power products and services marketed by SNR. The Marketing Plan has the flexibility to accommodate these changes. Western was a cooperating agency in Reclamation's PEIS process.

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866. No clearance of this notice by the Office of Management and Budget is required.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to services and involves matters of procedure.

Dated: November 21, 2003.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 03–29984 Filed 12–1–03; 8:45 am]

BILLING CODE 6450–01–P

COUNCIL ON ENVIRONMENTAL QUALITY

National Environmental Policy Act Task Force; Meeting

AGENCY: Council on Environmental Quality.

ACTION: Notice of public meeting.

SUMMARY: The Council on Environmental Quality (CEQ) established a National Environmental Policy Act (NEPA) Task Force to review the current NEPA implementing practices and procedures in the following areas: Technology and information management; federal and intergovernmental collaboration; programmatic analyses and subsequent tiered documents; and adaptive management and monitoring. In addition, the NEPA Task Force reviewed other NEPA implementation issues such as the level of detail included in agencies' procedures and documentation for promulgating categorical exclusions; the structure and documentation of environmental assessments; and other implementation practices that would benefit federal agencies.

''The Task Force Report to the Council on Environmental Quality—Modernizing NEPA Implementation'' was published and presented to CEQ on September 24, 2003. The Report contains recommendations designed to improve federal agency decision making by modernizing the NEPA process. To further the work of the NEPA Task Force, CEQ is holding a series of regional public roundtables to raise public awareness of the NEPA Task Force draft recommendations and discuss the recommendations and their implementation. The Southern Regional Roundtable will be held on December 11 and 12 at the historic Cadre Building, 149 Monroe Ave, Memphis, Tennessee. Information about the location is at *http://www.cadrebuilding.com/*. The Memphis Roundtable is co-hosted by the Southern Environmental Law Center, Duke Environmental Leadership Program at Duke University's Nicholas School of the Environment and Earth Sciences, and The Environmental Policy Information Center at Jacksonville State University. Representatives from important constituent groups that have worked on NEPA issues have been invited to participate in a discussion of the recommendations. Announcements of future roundtables will be published on the NEPA Task Force web site and in the **Federal Register**.

DATES: The southern regional public roundtable will be held on December 11 and 12. The December 11 session will begin at 9 a.m. and interested members of the public will have an opportunity to present their views at 3:30 p.m. following the roundtable discussion. That session will end in the evening after the publics' views have been presented. The session on December 12 will begin at 9 a.m. and interested members of the public will have an opportunity to present their views at 11 a.m. following the roundtable discussion.

ADDRESSES: Interested parties can review the Task Force report via the CEQ Web site at *http://www.whitehouse.gov/ceq/* or the NEPA Task Force Web site at *http://www.ceq.eh.doe.gov/nft/*. If you would like a printed copy, please mail a request to The NEPA Task Force, 722 Jackson Place, NW., Washington, DC 20585, or contact Bill Perhach at (202) 395–0826 to request a copy.

Dated: September 25, 2003.

James L. Connaughton,

Chairman, Council on Environmental Quality.

[FR Doc. 03–29873 Filed 12–1–03; 8:45 am]

BILLING CODE 3125–01–M

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Equal Employment Opportunity Commission.

ACTION: Notice of information collection—new: The Equal Employment Opportunity Commission's ''Freedom to Compete'' Award.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. chapter 35), the Commission announces its intent to submit to the Office of Management and Budget (OMB) a request to approve a new information collection as described below.

DATES: Written comments on this notice must be submitted on or before February 2, 2004.

ADDRESSES: Comments should be submitted to Frances M. Hart, Executive Officer, Executive Secretariat, Equal Employment Opportunity Commission, 10th Floor, 1801 L Street, NW., Washington, DC 20507. As a convenience to commentators, the Executive Secretariat will accept comments transmitted by facsimile (''FAX'') machine. The telephone number of the FAX receiver is (202)