

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.