5.1.1.1

SECTION 5
PROOF-OF-CONCEPT ANALYSIS

5.1 INTRODUCTION

The methods for identifying, evaluating, and acquiring power resources to replace the useable generating capability lost at GCD were discussed in the preceding sections of this report. In this section, these methods are demonstrated by testing them under conditions similar to those Western may actually encounter during the replacement resource acquisition process. To prepare this demonstration, an extensive data gathering, analysis, model development, and model implementation effort was undertaken, collectively referred to as the "proof-of-concept" analysis.

Because of the extensive geographic span of Western's marketing area, the proof-of-concept analysis involved developing a model of a large part of the interconnected electrical system in the western United States, covering the Rocky Mountain and Desert Southwest areas of the WSCC region. It was also necessary to identify data sources accessible to Western, and to gather, process, and integrate a large amount of data into the models. The modeling of such a large area required a significant investment of time and effort, but produced integrated modeling tools which will form the basis for a useable resource analysis system which will benefit Western and its customers not only for the Replacement Resources Process, but in other resource planning functions as well.

An extensive and detailed modeling approach is necessary to provide accurate evaluations of the value of replacement resources. A summary of the principal benefits of a detailed interconnected system model is provided below:[1]

- The GCP Act required the Replacement Resources Process to include the impacts of replacement power on the transmission system. The ability to integrate the modeling of replacement resources within the SLCA/IP transmission system is therefore an important consideration in developing methods and tools. Use of a multi-area interconnected system model is especially important because of its ability to model more complex transmission system interactions, such as the SRP Exchange Agreement.[2]

- The ability to simulate the interaction of replacement resources with other customer resources, Western resources, and the economy energy market is a key requirement. To consider these effects, the model must represent multiple electric systems divided among multiple load/resource areas (also referred to as "transmission" areas). A multi-area model represents the effects of external transmission constraints and the dynamic effects of load and resources on spot-market energy transactions.
- The evaluation of any alternative for replacement power must account for energy displacement and sales opportunities in the spot power market. Estimating the price and the location of these spot-market energy transactions is a significant part of performing a detailed evaluation of SLCA/IP's net purchased power costs. Given the current and projected market conditions under deregulation, and regional capacity surpluses, capturing these complex interactions through a multi-area production cost and dispatch simulation is even more important.
- Use of a multi-area model developed, marketed commercially, and offering user support will reduce the time requirements, and will likely increase the understanding and acceptance of the model by SLCA/IP customers.

5.1.1 PROCESS

The goal of the proof-of-concept analysis was to develop an integrated system of models for proposal evaluation, and to demonstrate their use through examples. The five recommended steps for evaluation of proposals for replacement power of over one-year duration were identified in Section 4.3.3, and are summarized below.

1. Calculate the levelized per-unit cost (of each supply option proposed) as a function of capacity factor during on-peak hours.
2. Rank the proposals based on the levelized per-unit cost.
3. Based on the rankings determined in Step 2, select the higher ranked proposals and prepare an integrated analysis simulating Western's resource use within the SLCA/IP integrated system and the WSCC bulk power market for the intended acquisition period.
4. Re-rank proposals based on levelized, per-unit cost to SLCA/IP customers using the results of Step 3.
5. Produce a cost curve relating the amount of power available at the lowest cost (based on levelized, per-unit cost).

Before these steps could be demonstrated, it was first necessary to identify the system of modeling tools to be used, and to select appropriate models to develop or modify for the proof-of-concept analysis. Then, the selected models were implemented using actual system data, in order to demonstrate their use. The most complex part of the process was modeling Western's resource use within the SLCA/IP integrated system and the WSCC bulk power market. This modeling effort comprised the majority of the proof-of-concept analysis.

A potential course of action could have been to implement the models using system data already existing from other studies, supplemented with "example" or "representative" data. The course of action used for the proof-of-concept analysis was to take a more comprehensive approach to model implementation, which involved identifying data sources, gathering most of the data from these sources, processing the data, and constructing comprehensive implemented models using this data. This more comprehensive approach offered several advantages, the most important of which were:

- confidentiality concerns with respect to existing data from other studies were avoided;
- the data gathering, data processing, and data entering processes were tested and confirmed, rather than testing only the models themselves;
- the accuracy and appropriateness of an integrated system model using publicly-available data sources were tested;
- the use of actual rather than example data should provide results which give Western and its customers more confidence in the feasibility of the methods proposed;
- the data implementation resulted in a useful database for Western to begin with for actual evaluations; and
- the models developed during the proof-of-concept analysis are now in a more advanced stage of implementation, reducing the amount of additional work for Western prior to performing actual replacement resource use.

Because of the significant preparatory data gathering and modeling necessary prior to evaluation, the proof-of-concept analysis consisted of work beyond the five evaluation steps listed previously. The following are the major steps completed in the proof-of-concept analysis, each of which is discussed in a sub-section of the report as shown below:

- gathered data and implemented the MULTISYM model for a significant portion of the WSCC system (Section 5.2);
- utilized MULTISYM to develop the “base case” model, without WRP (Section 5.3);
- identified representative resource alternatives for integrated analysis (Section 5.4);
- developed the screening tool and demonstrated its use on the representative resources (this covered steps 1 and 2 of the evaluation process above, and is discussed in Section 5.5);

- performed an integrated analysis of each resource to simulate its integration into the Western and interconnected WSCC system (step 3 above, Section 5.6);
- showed results of integrated MULTISYM model for base case, and for each alternative resource (step 4 above, Section 6.2);
- updated levelized-cost analysis using results from integrated model (Section 6.3);
- described application of results to Western/customer needs through cost curves (step 5 above, Section 6.4);
- showed the impact of the replacement resources on SLCA/IP rates (Section 6.5);
- described methodology for addressing risks through sensitivity analysis (Section 6.6); and
- analyzed and interpreted the results of the overall proof-of-concept analysis (Section 6.7).

As shown above, the first five of these steps are described in this section, while the last six items, covering the results of the analysis, are presented in Section 6.

5.2 MULTISYM MODEL IMPLEMENTATION

Implementation of the MULTISYM model involved gathering, evaluating, processing, and entering an extensive amount of data. To shorten and simplify presentation of the modeling details, most information on model implementation is presented as lists of items and tasks.

Use of the hourly production model MULTISYM allowed Western to accurately model:

- the effects of hour-to-hour price variations;
- the changes in spot energy prices with level of transaction;
- the effects of transmission constraints; and
- the influence of changing load and resource conditions.

Implementation of the MULTISYM model involved a sequential series of tasks, each of which is discussed under a topic heading below.

5.2.1 SYSTEM TOPOLOGY

System topology includes not only the representation of the individual systems modeled, but also the transmission interconnections between systems. The following items were key aspects in determining system topology:

- MULTISYM has the capability to model independent systems through the use of transmission areas
- Transmission between systems is represented by links between the transmission areas representing the systems
- Transmission areas fall within control areas[3]
- Systems modeled included all SLCA/IP customers plus six large regional investor owned utilities (IOU) that have significant purchase/sale transactions with the customers
- The regions modeled were those where the SLCA/IP firm-power customers are located (Utah, Arizona-Nevada, Colorado-Wyoming, and a small part of New Mexico)
- Other systems modeled externally were the California market and the New Mexico market, which were represented by non-firm sale transactions[4]

The simplified map on the following page (Figure 5-1) illustrates the complex system topology modeled in the proof-of-concept analysis. Items shown on the figure are defined on the two page table which follows.

[INSERT Figure 5-1 System Topology]

(MULTISYM TRANSMISSION AREA MAP - FILE = MRDS5MAP.DOC)

TABLE 5-1

SYSTEM LAYOUT DEFINITIONS

SLCA/IP CUSTOMERS - UTAH

UAMPS	Beaver City Municipal Electric Light & Water
	Blanding Electric Department
	Bountiful City Light & Power
	Enterprise Electric Department
	Ephraim Light & Power
	Fairview Municipal Light & Power Plant
	Fillmore City Electric Department
	Heber Light & Power Department
	Holden Electric Light System
	Hurricane City Power
	Hyrum City Corporation
	Kanosh Electric Department
	Kaysville City Corporation
	Lehi City Power
	Logan City Municipal Light & Power
	Meadow Town Corporation
	Monroe City Electric Light Department
	Morgan City Corporation Electric Department
	Mt. Pleasant Municipal Electric Light & Power Department
	Murray City Power Department
	Oak City Electric Department
	Page Electric Utility
	Paragonah
	Parowan City Electric Department
	Payson City Corporation
	Price Municipal Corporation
	Santa Clara
	Spring City Light & Power Plant
	Springville Municipal Power & Light Department
	St. George City Water & Power Department
	Strawberry Electric Service District
	Utah State University
	Washington
	Weber Basin Conservancy District
DGT	Bridger Valley Electric Association, Inc.
	Central Utah Water Conservancy District
	Dixie Escalante Rural Electric Association, Inc.
	Flowell Electric Association, Inc.
	Garkane Power Association, Inc.
	Kanab
	Moon Lake Electric Association, Inc.
	Mt. Wheeler Power, Inc.
UMPA	Utah Municipal Power Agency
SM_PACE	Brigham City Light & Power
	Defense Department, Odgen
	Helper City Light & Power Department
	Hill AFB
	Tooele Army Depot
	University of Utah

SLCA/IP CUSTOMERS - ARIZONA/NEVADA

SM_CRC	Colorado River Commission of Nevada
NTUA	Navajo Tribal Utility Authority
SM_SRP	Chandler Heights Citrus Irrigation District
	Electric District No. 4, Pinal County
	Electric District No. 5, Pinal County
	Electric District No. 5, Maricopa County
	Electric District No. 6, Pinal County (partial)
	Ocotillo Water Conservation District
	Queen Creek Irrigation District
	Roosevelt Irrigation District (partial)
	Roosevelt Water Conservation District
	San Tan Irrigation District
SM_WALC	Arizona Power Pooling Authority
	Safford Municipal Department, City of
	San Carlos Irrigation Project
	Thatcher Municipal Utilities
	Welton-Mohawk Irrigation Drainage District
SM_APS	Ak-Chin Indian Community
	Colorado River Agency
	Electric District No. 3, Pinal County
	Electric District No. 6, Pinal County (partial)
	Electric District No. 7
	Luke AFB
	Maricopa MWCD No. 1
	Roosevelt Irrigation District (partial)
	Yuma Proving Ground
SRP	Salt River Project Agricultural Improvement & Power District

TABLE 5-1
(Continued)

SLCA/IP CUSTOMERS - COLORADO/WYOMING

WMPA	Willwood Light & Power Wyoming Municipal Power Agency
TSGT	Delta Municipal Light & Power Fort Morgan Electric Light Department Frederick Municipal Light System Gunnison Light & Water Department Holyoke Municipal Light & Power Department Pueblo Army Depot Torrington Electric Light Department Tri-State Generation & Transmission Association, Inc. (LM) Tri-State in UC Wray Light & Power Department
CO_SPRING	Colorado Springs Utilities
PRPA	Platte River Power Authority
SM_PSCO	Center Municipal Electric Light & Power Systems Glenwood Springs Electric System Grand Valley Rural Power Lines Inc. Holy Cross Electric Association Inc. Intermontain Rural Electric Association Lamar Utility Board Raton PSC (ARPA) Yampa Valley Electric Association Inc.
SM_MEAN	Aspen Municipal Electric System Fleming Electric Light Department Haxtun Municipal Light & Power Department Oak Creek Electric Department Yuma Municipal Light & Power

SLCA/IP CUSTOMERS - NEW MEXICO

PEGT	Plains Electric Generation & Transmission Cooperative Inc. Truth or Consequences Electric Utility
SM_PNM	Department of Energy (Albuquerque Operations Office) Gallup Joint Utility Holloman AFB Kirtland AFB Los Alamos County
FARM	Aztec Utility System Farmington Electric Utility

WAPA RESOURCES

SRP_EXCH	SRP Exchange Resource (Glen Canyon)
WAPA_ASP	Blue Mesa Crystal Collbran Morrow Point Rio Grande
WAPA_C_H	SRP Exchange Resource (Craig) SRP Exchange Resource (Hayden)
WAPA_FG	Flaming Gorge Fontenelle
WAPA_GC	Glen Canyon
WAPA_SJ_FC	San Juan - APS, PNM, SRP Exchange Resource; Four Corners - APS, PNM TEP, SRP Exchange Resource

INVESTOR-OWNED UTILITIES

NPC	Nevada Power Company
TEP	Tucson Electric Power Company
APS	Arizona Public Service Company
PACE_UT	PacifiCorp Eastern Division-Utah
PACE_WY	PacifiCorp Eastern Division-Wyoming
PSCO	Public Service of Colorado
PNM	Public Service of New Mexico

TRANSMISSION NODES

WAPA_UT_S

WAPA_UT_N

WAPA_LM

WAPA_TOT5

NM2_TOT

NOTE: The five New Mexico contractors currently not receiving SLCA/IP allocation were not included (Roosevelt County Electric Cooperative, Lea County Electric Cooperative, Cannon AFB, Central Valley Electric Cooperative, and Farmers Electric Cooperative Inc. of New Mexico).

5.2.1.1 TRANSMISSION AREAS

The following are the characteristics of transmission areas within MULTISYM:

- Transmission areas can have load, resources, or both
- Transmission areas can have both primary and secondary spinning reserve requirements
- Each transmission area can have unique values for the cost of energy not served and dump power price
- Transmission areas need not necessarily correspond to physical transmission arrangements, and can be defined in the most useful way for the purposes of modeling the key system characteristics
- Each transmission area can have one hourly load representation; if more than one system is included in the transmission area then the transmission area load represents the combined load
- Individual transmission areas can be linked to other transmission areas
- Only one link can be defined between two transmission areas; however, a transmission area can be linked to several other transmission areas
- Transmission link characteristics can be defined separately for each direction, and include contract line capacity, losses, and wheeling costs.

Several types of transmission area representations were used in the proof-of-concept analysis, including:

- SLCA/IP customer load areas - Large customers with their own resources were modeled in separate transmission areas. Smaller customers with similar purchase power and/or transmission arrangements, or within the same control area, were grouped together (with a few exceptions for certain control areas).[5] The portion of customer load served by SLCA/IP resources was also accounted for separately in the MULTISYM model.[6]

- Regional IOU customer areas - The six large regional utilities that provide a significant portion of power to customers through firm and non-firm purchase arrangements were modeled. The IOU's projected hourly loads, resources and purchase/sale transactions were modeled within MULTISYM.
- Resource-only transmission areas - Western resources were modeled as three separate transmission areas, based on their location. Three generating resources (San Juan, Four Corners and a portion of Palo Verde) were also modeled in separate transmission areas to assist in modeling transmission arrangements.
- Nodes (transmission areas with no loads or resources) - Nodes were used to model key transmission interconnections with constraints.

5.2.1.2 CONTROL AREAS

Control areas can be defined separately from transmission areas in MULTISYM to allow for definition of control area operating reserves. Each system modeled was assigned to a unique control area based on data reported to WSCC. Control area information was considered in assignment of customers to transmission areas, although for some small customers, there were exceptions made to simplify the model.

5.2.1.3 SRP EXCHANGE AGREEMENT

Under the terms of the SRP Exchange Agreement, the Salt River Project Agricultural Improvement and Power District (SRP) exchanges output from its shares of Craig Unit 1, Craig Unit 2, and Hayden Unit 2 (in northwest Colorado), and Four Corners Units 4 and 5 (in northwest New Mexico) to Western for like power delivered by Western, mainly from GCD, to SRP in Arizona. Operation details of the SRP Exchange Agreement were discussed in Section 3.3.1.3. Previous modeling of this exchange has been accomplished external to hourly production cost model simulation. MULTISYM, because of its multi-area modeling capability, was used to represent the exchange as it actually would occur on an hourly basis through the use of modeling transmission links between the various transmission areas involved.[7]

5.2.1.4 NTUA Exchange Agreement

For the exchange agreement between Western and the Navajo Tribal Utility Authority, Western delivers approximately 22 MW of Glen Canyon generation when available to NTUA in exchange for 22 MW of NTUA generation delivered to Western in New Mexico. Due to the small size of this exchange (and wheeling) agreement, the NTUA Exchange was not explicitly modeled, but rather treated as wheeling in the proof-of-concept analysis.

5.2.2 DATA REQUIREMENTS

5.2.2.1 Confidentiality

A major issue with respect to gathering data from other utilities is confidentiality. In the power system cost evaluations prepared as part of the GCD-EIS and the EPM-EIS, the confidentiality of data supplied voluntarily by some electric systems has been at issue. While federal agencies and their customers have sought the best, most current information, many electric systems provide information only if its use and disclosure was limited. As a result, review of the data by others has been difficult and time-consuming to arrange. Data access restrictions for the Replacement Resources Process could impair the credibility of the evaluation results and contribute to misunderstanding and apprehension on the part of SLCA/IP customers and the public.

With the increasing availability of load, resource, and transmission data through publicly-accessible databases, the benefits of marginally better quality data restricted by confidentiality agreements do not offset the costs. Western will avoid using existing system information whose dissemination is restricted by a confidentiality agreement wherever possible. To the extent that Western has concerns regarding publicly-available load and resource information, specific electric systems can be contacted to request better information, preferably without confidentiality restrictions.

However, if requested to do so by power suppliers responding to an RFP, Western will be prepared to keep confidential information specifically identified as confidential (e.g., specific location of a generating unit or point of delivery to Western, or information that would identify the entity making the proposal).

5.2.2.2 IDENTIFICATION OF DATA SOURCES

A critical portion of the research and development work for this report involved identifying, investigating and using data from sources available to Western. The principal data source used to construct the MULTISYM model of Western's marketing area was Resource Data International, Inc. (RDI), an information services firm that specializes in electric utility industry databases, syndicated studies, and consulting. RDI was selected primarily because it is both comprehensive and readily available to Western.[8]

An overall list of the key data sources which Western intends to use in the Replacement Resources Process, as tested in the proof-of-concept analysis, is provided below.

- RDI
- FERC Form No. 1 (filed by IOUs)
- EPRI Technical Assessment Guide (TAG)
- Electric World Directory of Electric Power Producers
- NERC Generating Availability Data System (GADS)
- FERC Bulletin Board System (BBS)
- Western's in-house data sources
- Utility resource plans and IRPs

5.2.3 DATA COLLECTION AND PROCESSING

Data was collected simultaneously with the modeling effort. The type of data and level of detail required for purposes of the proof-of-concept analysis varied, depending on what was required to implement the model. The general types of data collected are each discussed below.

5.2.3.1 GENERATING RESOURCE DATA

The sources for generating resource data were as follows:

- RDI data (primary source)
- Electric World Directory of Electric Power Producers
- FERC Form No. 1 (for IOU's)
- Utilities' current resource plans or IRPs

MULTISYM allows modeling of several generation types, including thermal units, hydroelectric units, and pumped-storage units, each with its own unique set of characteristics. Jointly-owned generating resources required special modeling considerations, as follows:

- Each utility's share of joint resources was located in the respective utility's transmission area
- Each individual share was assumed to have respective minimum load requirements, and the same dispatch and commit priority
- Individual shares were linked together using MULTISYM's Rules of Existence Logic for forced outage and maintenance outages

Non-federal hydroelectric generation was modeled based on RDI data, which provided 1994 generation and capacity for each hydroelectric resource. Generation was summarized by customer. Small projects within a transmission area were grouped together and modeled as one resource

Other generating unit characteristics and the modeling assumptions used in the proof-of-concept analysis are reviewed below.

<u>Scheduled and Forced Outages</u>

Periods when generating units are not available to serve load are typically referred to as outages. Maintenance outages represent unavailability due to routine scheduled (planned) maintenance. Utilities attempt to schedule these outages during low load periods, and for larger units, also often coordinate with other interconnected utilities to minimize system reliability effects. The other major category of generating unit outage is a forced outages, when units are taken out of service for repair due to an unplanned event. These outages occur more or less randomly.

Maintenance outages can be scheduled by MULTISYM using a "distributed maintenance" method.[9] This simplified method was used for most resources in the proof-of-concept analysis. A maintenance outage schedule for each generating unit can also be directly entered into MULTISYM, which more accurately represents the system impact for long outages of larger units.[10] Forced outage rates used for the proof-of-concept analysis were based on average rates for generating unit size and fuel type from NERC GADS data.

Fuel Costs

Current fuel costs were based on RDI data. Fuel cost projections for the proof-of-concept analysis used forecast data from the Energy Information Administration.[11]

Heat Rates

The average heat rate provided in RDI was used for the proof-of-concept analysis, supplemented by historical fuel burned reported in RDI, and net generation for the station.

Other Operating Characteristics

A minimum load was assumed for each unit based on the type of unit. Minimum up and down times were also based on type of unit.[12] Unit dispatch and commitment parameters were based on the size and type of unit, and usage information provided in the RDI database.[13]

5.2.3.2 LOAD DATA

Data sources for load data were:

- historical energy sales and peak demand from 1994 - from the 1996 Electric World Directory of Electric Power Producers;
- load forecasts for some customer systems already provided to Western;[14]

- RDI database; and
- load forecasts and hourly load files - from the FERC Bulletin Board System (BBS).

For the proof-of-concept analysis, hourly load schedules were developed from data obtained from RDI and the FERC BBS. In cases where the hourly load patterns were not available, representative load shapes based on capacity factor and geographic location were used.

5.2.3.3 PURCHASE/SALE TRANSACTIONS DATA

Firm Transactions

Firm-power purchase and sales transactions were the most difficult to model because of their proprietary nature. Historical data from RDI was used to identify firm purchase and sale transactions. Limited additional information available in this area was taken from IRPs and wholesale transactions as reported in FERC Form No. 1.[15] Historical FERC Form 1 data was then used to determine the schedule of the purchase or sale.[16]

MULTISYM does not currently have the capability to locate a firm purchase in one transmission area and link the supply to a specific system in the same or a different transmission area.[17] Therefore, for the proof-of-concept analysis, off-setting sales and purchases were used to model the transactions. Firm purchases and sales between systems modeled were represented as two separate resources with corresponding schedules.

Non-Firm Transactions

For non-firm purchase/sale transactions, data sources were FERC Form No. 1 and RDI data. These transactions, also known as economy energy transactions, were modeled by allowing such transactions to take place through the transmission links included in the analysis, just as in actual utility practice.

Non-firm transactions outside of the modeling area were modeled explicitly through aggregated non-firm purchases. The California market was defined with six separate sales with varying capacity and increasing cost. The capacity and price for each sale was defined on a monthly basis, and the proportionate share of each sale was located in three transmission areas.[18] For the New Mexico market, three non-firm sales were included.[19]

5.2.3.4 SLCA/IP Resource Allocation Data

The contract allocations of SLCA/IP power used in the proof-of-concept analysis were based on Western's interim seasonal CROD allocations. These seasonal allocations were divided into monthly allocations of energy and capacity based on information from Western and its customers. The contract allocations were then used to determine actual resource generation, as discussed below.

5.2.3.5 SLCA/IP Generation

As described in Section 4.4.1, the CRSS model was used to represent the Colorado River System and determine the monthly hydroelectric generation for the SLCA/IP projects.[20] This CRSS analysis contained 86 traces of monthly capacity and energy for Fontenelle, Flaming Gorge, Blue Mesa, Morrow Point, Crystal and GCD for the water years 1992 through 2012.[21] The monthly generation representing the total SLCA resource was developed for each trace by summing the monthly generation determined in the CRSS model for each of the six sites. This resulted in 86 monthly generation patterns for the years 1992-2012, from which relevant portions were used in the proof-of-concept analysis.

The 86 annual energy patterns were sorted and ranked to identify a representative minimum, lower quartile, median, average, upper quartile and maximum energy trace for each year. The review included a plot of annual energy for each year in the study period, total energy for study period, and monthly shape of the energy.

The annual energy and total energy were used to narrow the selection to a few traces, and the monthly energy was then used to select the representative trace. The trace representing average generation was selected for purposes of the proof-of-concept analysis.[22] The projected monthly capacity and energy available from the Rio Grande and Collbran projects were then included based on historical data for these projects.

Monthly Minimum and Maximum Operating Capacity

The following steps were used to determine the monthly minimum and maximum operating capacity for each CRSP resource for the proof-of-concept analysis:

- GCD - The monthly generation from CRSS for the selected trace was used to develop the maximum and minimum monthly capacities for GCD. A modified version of the Geometric Model (see Appendix B), a post-processing routine developed by Western, was used to simulate the operating constraints of the MLFF alternative. In addition to the monthly capacity and generation data, the post-processor also required the monthly Lake Powell elevation, which was based on the CRSS data.
- Fontenelle - Both the maximum monthly capacities and monthly generation for Fontenelle from CRSS for the selected trace were used directly in the analysis. The minimum monthly capacities for Fontenelle were determined from the projected monthly generation amounts, since the releases are steady throughout the month to maintain a downstream fishery.
- Flaming Gorge - Both the maximum monthly capacities and monthly generation for Flaming Gorge from CRSS for the selected trace were used directly in the analysis. The minimum monthly capacities for Flaming Gorge were developed by converting Argonne's[23] representation of the minimum monthly flow rates for average hydrology from the USFWS Biological Opinion[24] into megawatts.
- Crystal - Both the maximum monthly capacities and monthly generation for Crystal from CRSS for the selected trace were used directly in the analysis. The minimum capacity was determined based on a minimum release of 300 cfs below the Gunnison Tunnel.
- Blue Mesa and Morrow Point - Both the maximum monthly capacities and the monthly generation for Blue Mesa and Morrow Point from CRSS for the

selected trace were used directly in the analysis. These plants can be turned off when required, so the minimum for both of these plants was set to zero.

In addition, the integrated projects, Collbran and Rio Grande, were represented in the model based on historical operation of the projects. Project use was included as a load requirement for Western to serve.

5.2.3.6 OTHER WESTERN FACILITIES

The following assumptions were used for other non-SLCA/IP Western resources within the proof-of-concept analyses. Modeling of these resources may be updated by Western for the actual replacement resource evaluations.

Boulder Canyon Project

Allocations of Boulder Canyon were modeled as a hydroelectric resource located in each customer's transmission area. The historical monthly generation for each project was provided by Reclamation, and the historical annual generation was calculated. The year closest to the average annual generation was used to represent the monthly shape; and the projected annual generation was scaled to the selected shape. This generation was then compared to RDI historical data for 1993 and 1994.

Parker-Davis Project

Allocations of Parker-Davis were modeled as a hydroelectric generating resource located in each customer's transmission area.[25]

As with Boulder Canyon, historical monthly generation for each project was provided by Reclamation, and the historical annual generation was calculated for each year. The year closest to average annual generation was selected to represent the monthly shape, and the annual generation was scaled to the selected shape. When the results were compared to RDI historical data for 1993 and 1994, review of the data indicated that the annual output varies significantly.

Loveland Area Project (LAP)

Allocations of LAP were modeled as a hydroelectric resource located in each customer's transmission area. The monthly shape for each season was determined based on historical data for capacity and energy. [26] The seasonal allocation was applied to the monthly load shape to determine monthly generation and capacity. LAP customers were assumed to schedule their share of the project independent of the LAP resources and other users (a load-based schedule).

5.3 DEVELOPMENT OF " BASE CASE"

After the MULTISYM model representation of the system was constructed using the system topology and resource and load data reviewed above, the " base case" for the proof-of-concept analysis was developed. The base case is the completed representation of the WSCC system model on MULTISYM without replacement resources. The proof-of-concept analysis was set up using 1994 as the base year (beginning year for data). The analysis was set up for a five year period, from 1996 through 2000. The base case represents the CRSP system with flow restrictions at Glen Canyon and spot market energy purchases.

The following steps were involved in completing the base case:

- Develop SLCA/IP AHP level
- Develop initial base case (without replacement resources)
- Test the data (benchmarking to compare to historical operation)
- Finalize base case

5.3.1 DEVELOPMENT OF AVAILABLE HYDROPOWER (AHP)

Western will provide projections of AHP each season to SLCA/IP customers. These projections will incorporate current reservoir levels, the current annual operating plan for water releases, planned habitat maintenance or beach-building releases, planned research flows, and any planned changes in flow restrictions at GCD or other SLCA/IP plants. Western must post-process the CRSS or PRYSM data to reflect station use and losses, and to calculate maximum and minimum generation under the various ramp rate restrictions using a geometric or peak-shaving algorithm.

The uncertainty in the absolute level of AHP (because of variable water conditions and the individual customer’s hourly schedule of AHP), combined with the uncertainty in Western’s hourly schedule of SLCA/IP resources to serve load, creates a complex system to model. For the proof-of-concept analysis, several simplifying assumptions were used, including the following assumptions with respect to SLCA/IP and WRP resources:

- Average water conditions were assumed, with modified low fluctuating flow (MLFF) operations at GCD. As discussed in Section 4, Western may prepare the analysis for a range of expected water conditions during the actual evaluation of replacement resources.
- The hourly load shape of the customers’ CROD schedule was assumed not to change during the five-year study period. For longer-term purchases of WRP, Western may prepare the analysis for varying load shape over the study period.
- All SLCA/IP customers were assumed to purchase WRP and receive their allocated share of the WRP alternative. The total quantity of WRP evaluated, and each customer’s allocation, was determined based on a comparison of the contract monthly capacity and the available hydropower under average water conditions. The amount of WRP included in the actual evaluations will be based on those customers requesting WRP.

Based on these simplifying assumptions, an hourly shape for the customers’ schedule of AHP was developed for one representative year, which was then used to represent the customers’ hourly schedule of AHP for each year in the analysis. This shape was based on the projected monthly capacity of SLCA/IP resources for the year 2000, which represented the average monthly capacity over the five year period. The monthly AHP was calculated as the total

SLCA/IP capacity, reduced by the projected project use and Western's estimated planning reserve requirement.

The monthly AHP was then allocated to each customer according to the monthly CROD allocations. If the AHP was greater than the total monthly capacity in any month, the customer's monthly capacity was increased up to a maximum of their CROD. Alternatively, if the AHP was less than the total monthly capacity, each customer's monthly capacity was reduced proportionately.

5.3.1.1 INTEGRATED MODELING APPROACH

Each SLCA/IP customer was assigned to a transmission area representing a single utility or multiple utilities. This resulted in a total of 19 groups of SLCA/IP customers. For each group, a "main" transmission area was identified that represents the loads and resources for the group. In addition, a "SLIP" transmission area was identified for each group in order to model the SLCA/IP load to be served by Western's resources and WRP. This was done to ensure that SLCA/IP resources would be used to serve SLCA/IP customer load, and the economics of Western's customers could be separated from those of other utilities modeled on the interconnected system.

A two-step approach was used to estimate the hourly schedule of AHP and the hourly schedule of SLCA/IP resources to meet the AHP load (or SLCA/IP load). In the first step, the SLCA/IP contract was modeled from the perspective of the SLCA/IP customers. The hourly schedule for the customers' allocation of AHP was determined by simulating the interconnected system using MULTISYM. Each customer's SLCA/IP allocation was included in their resource mix and scheduled to meet their load, subject to the contractual monthly capacity as adjusted for available hydropower, monthly energy, and minimum take requirements. This resulted in a projection of the customer SLCA/IP hourly resource schedule, which was converted to an hourly load shape in the "SLIP" transmission area. The equivalent load shape was subtracted from the total load in the customer's "main" transmission area.

The second step then implemented the SLCA/IP contract from Western’s perspective as a load obligation. Western’s resources were scheduled to meet the SLCA/IP load shape in the MULTISYM model. As described previously, the SLCA/IP resources were located in three transmission areas. These transmission areas were connected to each other and to the SLCA/IP load areas with transmission links. The flow of generation from these transmission areas to the SLCA/IP load areas was controlled by the capacity limits defined for the links, whereby the Western resources would serve the SLCA/IP load first. The GCD resource representation was further refined to reflect the SRP Exchange Agreement, as described above in Section 5.2.1.3. The model simulation allowed any surplus to be sold to customers or IOU’s. If Western’s resources were insufficient to serve the SLCA/IP load, non-firm energy transactions were allowed to fill the remaining load.

5.3.2 BENCHMARKING THE MODEL

A type of benchmarking known as a backcasting analysis was completed for the historical test year of 1994 to verify the modeling of the system. The reasonableness of the modeling results for the base case were checked by comparing them to historical utility data. The resulting hourly schedule for Western’s resources, customer SLCA/IP hourly schedules, and the representation of the SRP Exchange Agreement, were checked for reasonableness against historical operations.

In addition, the following parameters from the analysis were reviewed during the backcasting:

- Capacity factor of major generating resources on all systems
- Transmission loadings on critical transmission paths
- Fuel cost and heat rates
- Generating unit outages
- Firm and non-firm purchase and sale transactions
- Generation of non-Federal hydroelectric resources

As a part of the backcasting process, modeling of several operating parameters were refined as required to ensure that the modeling methods and assumptions were appropriate for the purposes of the proof-of-concept analysis.[27] After refinements were implemented, results of the backcasting analysis confirmed that the overall representation of the integrated system was reasonable.

5.4 REPLACEMENT RESOURCE ALTERNATIVES

In the proof-of-concept analysis, the evaluation tools and methods recommended for use by Western in the Replacement Resources Process were tested using a realistic and representative set of replacement resource alternatives.[28] These alternatives were chosen to demonstrate the evaluation process and modeling tools, and to show that:

- the evaluation process is capable of differentiating the distinct characteristics of each resource alternative;
- the evaluation process estimates the effects of resource alternatives with respect to the SLCA/IP transmission system and other location-related factors;
- the estimated net costs to SLCA/IP are reasonable in absolute terms and in relation to one another; and
- the overall results of the resource alternative rankings and selection are reasonable in absolute terms and in relation to one another.

5.4.1 RESOURCE CHARACTERISTICS

The following describes the critical resource characteristics to be tested in the proof-of-concept analysis:

Purchase type: Four different types of purchases were selected, including firm capacity and associated energy, firm energy, firm capacity with energy exchange, and energy from a renewable resource. As discussed previously, Western may not need to purchase capacity (with or without reserves) as long as the current exception criteria for emergency conditions exist. However, Western may not limit the types of purchases considered, so a variety of purchases were included in the proof-of-concept analysis to test the model's capabilities.

Capacity delivery pattern: The alternatives selected include three variations in the pattern or shape of the capacity to illustrate the effects of WRP capacity varying by month, by season, or by purchase term. Two alternatives represent seasonal purchases in which the capacity was assumed to be uniform within a season. Monthly capacity variations were included for the monthly capacity purchases represented with the two other alternatives. One alternative includes energy delivered in a fixed pattern for the term of the purchase.

Pricing structures: For each of the four types of purchases modeled, representative pricing structures were selected. Firm-capacity purchases typically include a capacity charge and an energy charge as illustrated with the first two alternatives. A slight variation in the relative pricing level of the capacity charge and energy charge was included to illustrate the economics of a higher capacity charge and lower energy price (first alternative) as compared to a lower capacity charge and higher energy price (second alternative). The second alternative was designed to illustrate the capability of the model to price purchases at the hourly marginal cost of a particular utility. The third alternative, a firm-energy purchase, included an energy price higher than the first two alternatives, but no capacity charge. The fourth alternative represented a capacity-exchange purchase in which the energy received on-peak was repaid with off-peak energy. The fifth alternative represented a purchase with all energy generated priced at a fixed level. Finally, various escalation rates were included to illustrate how the economics of alternatives change over time.

Scheduling restrictions: A variety of scheduling restrictions or requirements were included. The first two alternatives included no minimum hourly schedule, no minimum energy take, and a maximum energy take. The third and fourth alternatives included no minimum hourly take, a minimum energy take, but no maximum energy take. The fifth alternative represented a non-dispatchable resource (i.e., Western would not be able to modify the hourly schedule for the resource). The actual hourly take by Western customers within the restrictions will be determined by the operation of the resource within the interconnected system as simulated by the MULTISYM model.

Location (delivery point): To illustrate the capability of the model to incorporate the effects of transmission constraints into the economic dispatch of the interconnected system, the five alternatives include four widely different geographical delivery points to Western’s system. Location differences can also impact the economics of alternatives through transmission losses and wheeling charges.

5.4.2 SELECTED RESOURCE ALTERNATIVES

The following is a brief description of the replacement resource alternatives selected for examination in the proof-of-concept analysis.

Alternative 1: Fixed Seasonal Block Purchase Delivered at Craig

A block (uniform monthly) firm purchase by season was assumed, with capacity and associated energy assuming no minimum take and up to an 80 percent capacity factor. The point of delivery to Western was Craig, Colorado. The capacity price was $3.50 per kW-month, escalating at 4 percent per year, and the energy price was $14 per MWh escalating at 3 percent per year.

Alternative 2: Fixed Seasonal Block Purchase Delivered at Pinnacle Peak

A block firm purchase with the same characteristics as Alternative 1 was assumed, with the point of delivery being Pinnacle Peak in Arizona. The capacity price was $2.50 per kW-month, escalating at 4 percent per year, and the energy price was based on the incremental cost of an Arizona IOU.

Alternative 3: Energy Purchase Delivered at Shiprock-Four Corners

A " firm-energy" purchase was assumed, with a maximum rate of delivery to meet monthly requirements, and a monthly minimum energy take of 50 percent of the monthly maximum rate of delivery. The point of delivery to Western was Shiprock-Four Corners in New Mexico, and the energy rate was $26 per MWh, escalating at 5 percent per year.

<u>Alternative 4</u>: Block Capacity-Exchange Delivered at PacifiCorp-Eastern Division

A block capacity exchange was assumed, with energy received during the on-peak hours and returned during off-peak hours at a ratio of 1.6 to 1. The exchange has a minimum monthly energy take of 60 percent of the capacity available during the peak hours. The point of delivery to Western was from PacifiCorp-Eastern Division.

<u>Alternative 5</u>: Renewable Energy Purchase Delivered at Craig

A block purchase of energy from a specific resource, a wind farm located in Wyoming, was assumed. The point of delivery was Craig, and the energy cost was a flat rate of $50 per MWh.

5.5 SCREENING ANALYSIS

The levelized-cost screening analysis covers steps 1 and 2 of Western's proposal evaluation process, as reviewed at the beginning of this section:

<u>Step 1</u>: Calculate the levelized per-unit cost (of each supply option proposed) as a function of capacity factor during on-peak hours.

<u>Step 2</u>: Rank the proposals based on the levelized per-unit cost.

The proposals Western receives for WRP will include various pricing structures, capacity levels, delivery points, and other characteristics as demonstrated by the resource alternatives identified above. The diversity of proposal pricing and other characteristics will make it difficult to determine the lowest cost alternative simply by reviewing them. On the other hand, preparing an integrated analysis for all responses received would be too time-consuming. To limit the number of alternatives evaluated in detail, a screening analysis was developed that provides a straightforward method to process the basic data, represent each alternative on a consistent basis, and create an economic ranking of the alternatives based on the estimated levelized per-unit cost at different capacity factors. Based on the results of the screening analysis, Western will be able to select the alternatives to be evaluated in detail using a fair and objective process.

5.5.1 DEVELOPMENT OF SCREENING TOOL

The tool developed to prepare the screening analysis was designed to evaluate the on-peak value of the resource alternatives. Although customers may schedule WRP during the off-peak hours, off-peak energy would not be part of the primary cost ranking, since replacement power is required to make up for shortfalls during on-peak, not off-peak load periods. Accordingly, energy available from an alternative during the off-peak load period was assumed to be sold as non-firm energy, to the extent this was economical based on the estimated non-firm market prices.

5.5.2 DEMONSTRATION OF SCREENING TOOL

The screening tool incorporates the levelized per-unit cost for each alternative, calculated for capacity factors ranging from 10 percent to 100 percent on-peak capacity factor. Only those capacity factors relevant to a particular alternative are shown (e.g., an alternative with a maximum energy take of 80 percent capacity factor would not be shown for the 90 percent and 100 percent capacity factors). For each capacity factor, the estimated annual amount of on-peak energy available to the customers and the estimated annual amount of off-peak energy available for the non-firm market was calculated for the evaluation period 1996 through 2000. The level of non-firm, off-peak sales was determined based on estimated non-firm market prices.

The net annual cost for each capacity factor was then calculated as the sum of all of the fixed costs, plus the variable costs, less the revenues from marketing off-peak energy. A levelized per-unit cost was calculated based on the net annual costs and annual on-peak energy, discounted to current year dollars, assuming a discount rate of seven percent.[29]

The results of the screening analysis for the replacement resource alternatives is summarized in the table below:

TABLE 5-2

SUMMARY OF LEVELIZED COST SCREENING ANALYSIS

	Alternative 1 Firm Capacity Block	Alternative 2 Firm Capacity Block	Alternative 3 Firm Energy	Alternative 4 Capacity Exchange	Alternative 5 Non-dispatchable Wind
Capacity Maximum (MW)	491	491	491	491	200
Capacity Average (MW)	434	434	227	227	100
On-Peak Capacity Factor					
Maximum	100%	100%	100%	100%	57%
Minimum	0%	0%	88%	60%	38%
Capacity Factor	Levelized Per Unit Cost (mills per kWh)				
10%	105.00	89.94			
20%	59.78	57.64			
30%	44.70	46.88			
40%	37.17	41.49			77.70
50%	32.64	38.26			72.57
60%	29.65	36.11		22.89	70.03
70%	27.53	34.57		22.89	
80%	25.94	33.42		22.89	
90%	24.70	32.52	29.67	22.89	
100%	23.70	31.80	29.46	22.89	

In an actual screening analysis, all proposed alternatives would be screened, and a number would be selected to carry forward to the integrated analysis discussed below. Non-economic factors may be used to determine which among closely cost-competitive offers will be considered in the integrated analysis. In the proof-of-concept analysis, the screening tool was demonstrated on five resource alternatives, all of which were pre-selected to be analyzed in detail.

For shorter-term seasonal replacement resource acquisition, the levelized-cost analysis screening tool described below may be useful in some circumstances as a tool to make short-term decisions without performing a more complex integrated analysis.

5.6 INTEGRATED ANALYSIS

The integrated analysis is step 3 of Western's proposal evaluation process, as reviewed at the beginning of this section:

Step 3: Based on the rankings determined in Step 2, select the higher ranked proposals and prepare an integrated analysis simulating Western's use of the resources within the SLCA/IP integrated system and the WSCC bulk power market for the intended acquisition period.

To prepare the integrated analysis, each WRP resource was modeled to simulate its integration into the Western and interconnected WSCC system. A separate replacement resource model run was prepared for each alternative, in which the WRP resource was added to the base case model developed earlier. Similar to the method developed for modeling the AHP level of the SLCA/IP resources (discussed in Section 5.3.1), a two step process was developed to represent the WRP alternatives and ensure that each customer would receive an allocated amount of WRP based on their needs.

In the first step, the customers' hourly schedule for the WRP alternative was determined. For some of the alternatives, the hourly schedule could be estimated directly from the description of the alternative, but most of the alternatives required an actual MULTISYM simulation to determine the hourly resource schedule. This hourly schedule was then converted to an equivalent load shape.

In the second step, the hourly load shapes developed in the first step were then located in the customer transmission areas, such that this load would be served by the SLCA/IP resources, including WRP. The total WRP resource was located in the appropriate transmission area based on its delivery point, and a MULTISYM simulation was executed for each WRP alternative. If surplus WRP was available, it was marketed as non-firm energy.

Detailed modeling considerations for each of the alternatives are reviewed below.

Alternative 1 was a seasonal fixed block purchase with a maximum energy take of 80 percent. The winter capacity for this resource was set at the maximum winter deficit for each year, and the summer capacity for this resource was set at the maximum summer deficit for each year. This alternative was modeled assuming that the maximum amount of power available would be scheduled. The WRP resource was modeled as a fixed energy resource at an 80 percent capacity factor.

Alternative 2 was also a seasonal fixed block purchase with a maximum energy take of 80 percent. The capacity for this resource was the same as for Alternative 1. The winter capacity was set at the maximum winter deficit for each year and the summer capacity was set at the maximum summer deficit for each year. As for Alternative 1, this purchase was modeled assuming that the maximum amount of power available would be scheduled. The WRP resource was modeled as a fixed energy resource at an 80 percent capacity factor.

Alternative 3 was a monthly energy purchase with a minimum energy take of 50 percent of the monthly capacity. The third alternative was assumed to be a firm-energy purchase and, as such, the supplier would not guarantee the delivery of the maximum capacity during all peak hours. Western would need to rely on its own resources or purchases from others to provide capacity in hours where the full capacity from this alternative was not available. An implicit capacity charge of $.75 per kW-month was included to account for this. This charge could represent a reservation charge that Western may pay to a supplier, for the right to schedule capacity in certain hours. Alternatively, this charge could represent the value of Western’s own resources to provide this back-up capacity. The monthly capacity was set at the total monthly deficit for each month, and no minimum hourly capacity was scheduled.[30]

Alternative 4 was a capacity energy exchange with the energy received during the peak hours returned during the off-peak hours at a ratio of 1.6 to 1, and a minimum monthly energy take of 60 percent of the capacity available during the peak hours. This required separate simulations using MULTISYM, because the customers' hourly schedule for this resource was not easily estimated.[31]

Alternative 5 was a renewable energy purchase from a wind farm. It was assumed that the wind resource was capable of providing a peak month average maximum capacity of 100 MW. Thus, the maximum capacity modeled in MULTISYM was assumed to represent the average maximum capacity for the resource, not the nameplate capacity for the project.[32] This was assumed to be a non-dispatchable resource, and was represented by a fixed hourly and seasonal energy pattern. Each customer or group of customers was allocated a pro-rated share of the resource.

ENDNOTES:

[1] For further details, see the discussion of these issues in Section 4.4.3.

[2] See Section 3.3.1.3 and Section 5.2.1.3 for a more detailed discussion of the SRP Exchange Agreement.

[3] In MULTISYM, transmission areas can be used to define a single utility, or several utilities combined into a single load shape. Each transmission area can be assigned to a control area for calculation of reserves. Specific resources within a transmission area can be assigned to a control area different than the control area that the transmission area is assigned to.

[4] These markets would add a great deal of size, complexity and cost to the model, which would not be a good trade-off for the additional information which would be gained.

[5] Separate transmission areas were defined to specifically identify SLCA/IP customers, identify transmission links, and simulate the flow of power for customers with partial requirements or full requirements contracts with another utility. To explicitly identify SLCA/IP customers, each IOU was modeled in a unique transmission area. Since it was not feasible to locate each SLCA/IP customer in a unique transmission area, some customers were grouped together. Several factors were used to determine the appropriate location for each customer. The largest customers with owned generation were identified and located in separate transmission areas. Smaller customers that either had minimal generation or no generation, and purchased a significant amount from one of the large customers was included in the large customer transmission area. Small customers that purchase the balance of their energy requirements from an IOU were grouped appropriately in transmission areas and linked to the corresponding IOU. The control area that each customer is assigned to was also used to determine the appropriate location.

Simplifying assumptions were also used for the proof-of-concept analysis (e.g., Tri-State East and West was modeled in one transmission area, and members of Deseret were modeled in one transmission area). These configurations can be re-examined and changed if needed for the actual evaluation process.

[6] SLCA/IP customer load areas were actually split into two components for the modeling, each of which was represented as a transmission area within MULTISYM. One transmission load area contained the loads which SLCA/IP resources (including WRP) serves, and the other contained the balance of the customer load. This was done to ensure that SLCA/IP resources (including WRP) were delivered to the customer’s transmission area and dedicated to serve customer load.

[7] SRP’s exchange power from Western, generated at GCD, is modeled as six separate but linked units (five units corresponding to each of the SRP Exchange Agreement units available to Western, plus the balance of GCD). When the exchange is operating (the units involved in the exchange are available), the units are treated as if they are dispatchable by the exchange utility, and available GCD power is reduced by the power used by SRP as part of the exchange.

[8] Western currently subscribes to RDI. As a part of Western’s subscription, most of the data needed is provided by RDI in a database format. Additional data can also be requested from RDI by special arrangement.

[9] Maintenance outages are distributed throughout the year with the objective of levelizing the weekly reliability indices (Loss of Load Probability, or LOLP). The weekly outage factor for each unit was a function of the unit's maintenance outage rate and the distribution factor computed for the week.

[10] In the proof-of-concept analysis, actual maintenance for Palo Verde based on the schedule provided in APS 1992 IRP was implemented to show an example of using actual maintenance schedules.

[11] Supplement to the Annual Energy Outlook 1995: Table 71 (Lower 48 Crude Oil Production and Wellhead Prices by Supply Region), Table 76 (Natural Gas Delivered Prices by End-Use Section and Census Division), and Table 86 (Domestic Coal Supply, Disposition, and Prices Mountain Census Division).

[12] Large coal-fired, gas-fired, or oil-fired steam turbines assumed to require one-week minimum down time, small steam turbines 24 hour minimum down time, combustion turbines no minimum up or down time

[13] Large coal-fired, gas-fired, and oil-fired steam turbines with a relatively low fuel cost (20 mills/kWh or less) were assumed to be base loaded and not cycled (modeled as must run at minimum load); large coal-fired, gas-fired, and oil-fired steam turbines with a relatively high fuel cost (higher than 20 mills/kWh) were assumed to be cycled (if taken down, they were assumed to be out for one week); small steam turbines, all combustion turbines and combined cycle, and some small diesel units assumed to be economically dispatched (no must runs); small diesel units and other units identified in the RDI database as emergency units were modeled as peak only or emergency units.

[14] These included load forecasts that Western received from customers dependent on Western's transmission system for their entire load.

[15] FERC Form 1 Sales for Resale Page 310 - 311 and Purchase Power Page 326 -327 (provides notes on some transactions including term).

[16] For 35 percent or less operating factor, peaking was assumed with no minimum scheduled at maximum for enough hours to produce annual energy reported 5 or 6 days per week. Over 35 percent operating factor assumed to be intermediate to baseload with a minimum capacity factor between 10-25 percent scheduled on off-peak hours. Peak hours were assumed to be either 5 days a week and enough hours to generate the reported capacity adjusted for off-peak generation, or 6 days a week and enough hours per day to generate reported capacity adjusted for off-peak generation.

[17] Western will pursue this with The Simulation Group (the firm which developed and licenses MULTISYM) to allow for this capability in future versions of MULTISYM.

[18] Based on 1996 BPA ACME as input to non-firm revenue analysis program (NFRAP), June 26, 1995. Only non-firm sales to California were included.

[19] The estimated capacity and pricing structure were based on CA market data, but 2 mills per kWh higher price than CA market was assumed.

[20] For the purposes of the proof-of-concept analysis, the August 1994 CRSS study by Reclamation simulating the MLFF alternative

monthly release volumes at GCD for the GCD-EIS was used as the primary source of data.

[21] The number of appropriate traces was based on the number of historical years available at the time the proof-of-concept analysis was prepared. The number of traces could be different in future analyses.

[22] The data used in the proof-of-concept analysis was for calendar years 1996 through 2000.

[23] *Relationships between Western Area Power Administration's Power Marketing Program and Hydropower Operations at Salt Lake City Area Integrated Projects (draft),* Argonne National Laboratory, January, 1994.

[24] *Final Recovery Implementation Program for Endangered Fish Species in the Upper Colorado River Basin*, U.S. Fish and Wildlife Service, September 29, 1987.

[25] The allocations were based on Federal Register July 29, 1987 for Parker-Davis Project. The losses were assumed to be 5 percent, and a 10 percent minimum (or run-of-river) balance was assumed to be available to shave peak load.

[26] LAP allocations were based on November 3, 1993 Federal Register, Final Post-1989 allocation. The representative monthly capacity and energy used in the proof-of-concept analysis was based on monthly average historical generation and capacity provided in the Loveland Area Resource Team's Draft Post-1999 Resource Study *(Draft Post-1999 Resource Study,* Loveland Area Resource Team, August 1994). Five percent losses were assumed, and a ten percent minimum schedule was assumed.

[27] For example, the actual hourly historical schedules of customers SLCA/IP allocation was compared to the results from the model. The simulated schedules were found to replicate the general pattern of the historical SLCA/IP schedules. Also, the hourly schedules of Western's resources were examined in the development of the appropriate representation of the SRP Exchange. At the time of the actual Replacement Resource evaluations, Western will prepare a similar backcasting effort with updated data, and refine modeling assumptions as appropriate to their effort.

[28] The purpose of the selected examples was to demonstrate the capabilities of the modeling tools to handle a wide-range of alternatives, not to prepare an actual evaluation that would result in the selection of a specific alternative.

[29] Levelized per-unit costs are calculated by first taking the annual cost for the resource in each year of the study adjusted by revenues from surplus sales, and reducing the cost for each future year by discounting the costs using a constant discount rate for each year into the future (7 percent in this case) which results in the net present value of the costs. A similar process is used to adjust the available on-peak energy for each year and calculate the net present value of energy. The net present value of the costs are then divided by the net present value of the energy to determine the levelized cost. Applying the net present value process to the energy component of the calculation captures the relationship between available energy and cost over the period analyzed.

[30] This alternative required two separate simulations using MULTISYM, because the customers' hourly schedule for this resource was not easily estimated. MULTISYM first scheduled the resource based on economics; if the minimum schedule was not met, MULTISYM

rescheduled the resource as a peak shaving resource with energy equal to the minimum monthly energy requirement. In the second step, the WRP resource was modeled as a limited energy resource with a minimum energy take of 50 percent, and no minimum hourly schedule to serve the allocated hourly share of WRP located in the SLIP transmission areas.

[31] MULTISYM has the capability to model capacity energy exchange purchases where the energy is returned the same week that it is scheduled, but a simplified approach was used for the proof-of-concept. A model simulation was made with no WRP resources and the average monthly off-peak marginal cost for selected transmission areas was reported. This information was used to estimate the cost of return energy. The resource was then modeled as a limited energy resource available during peak hours (from 7 a.m. to 11 p.m.), with a minimum energy take of 60 percent of the available on-peak energy, and no minimum hourly schedule. The resources were priced at the appropriate transmission area off-peak marginal cost times 1.6, representing the cost of return energy.

[32] Western's modeling of a renewable purchase for an actual evaluation will depend on the specifics of the project as well as the Inland Power Pool's treatment of renewable power. MULTISYM is capable of representing the characteristics of renewable power.