Appendix O

Analysis of Power and Energy Impacts to Glen Canyon Dam, Shortage Criteria EIS

This appendix contains a copy of a report prepared by the Western Area Power Administration entitled *Analysis of Power and Energy Impacts to Glen Canyon Dam, Shortage Criteria EIS*. The report describes the methodology and analysis conducted for energy resources at the Glen Canyon Powerplant. The analysis in Section 4.11 of this Final EIS uses information derived from this analysis of generation capacity and its associated economic value.

Analysis of Power and Energy Impacts to Glen Canyon Dam, Shortage Criteria EIS

July 30, 2007, Update for FEIS

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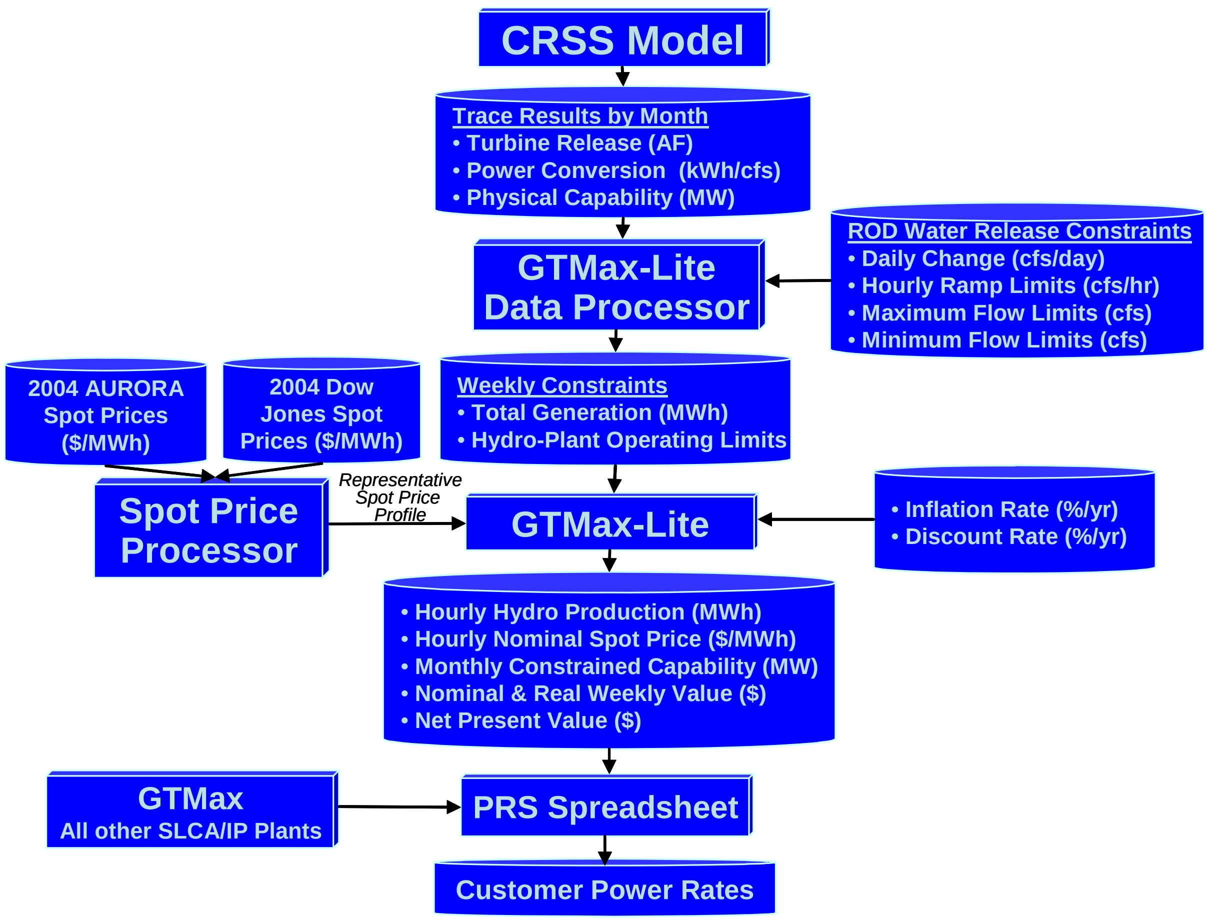
Methodology Overview

The methodology used by the Western Area Power Administration (Western) to estimate the economics of Shortage Criteria Environmental Impact Statement (EIS) alternatives is a multi-step procedure of data processing and computer simulations. A flow diagram depicting the major components of this procedure and component interactions is displayed in Figure 1. The procedure uses monthly results produced by the Colorado River Simulation System (CRSS) for each of the six EIS alternatives. This includes monthly values of turbine-water releases, power conversion factors, and the physical production capability of the Glen Canyon Dam (GCD) hydropower plant. The CRSS model also simulates operations for other Colorado River System Project (CRSP) reservoirs. However, EIS alternatives only impact the Glen Canyon Dam and are therefore the focus of this analysis.

Figure 1
Diagram Depicting Major Modeling Components and Processes



CRSS results along with operating constraints mandated by the Glen Canyon Dam EIS Record of Decision (ROD) are input into an Excel spreadsheet that prepares input data for a customized variation of the Generation and Transmission Maximization (GTMax) model. To distinguish this customized version from the original model, it is referred to as GTMax-Lite in this document. The Data Processor spreadsheet uses power conversion factors to translate CRSS releases and ROD constraints from water units into a power equivalent. For example, monthly turbine water releases specified in terms of acre-feet (AF) in CRSS output tables are converted into an equivalent electricity production in units of Mega-Watt-hours (MWh). The spreadsheet also selects a subset of CRSS results and calculates statistics that are analyzed in more detail by other processes.

Physical monthly operating limits for capacity and energy along with ROD operational constraints are used by the GTMax-Lite model to simulate hourly Glen Canyon Dam power plant generation levels. The model determines the hourly operation schedule over a 1-week period (i.e., 168 hours) that maximizes the economic value of the hydropower resource. The operation schedule produced by the model is within the physical limitations of the power plant and it complies with all environmental and institutional regulations.

The GTMax-Lite model uses a projection of market prices as a measure of the future economic value of hydropower generation. These prices heavily influence the generation schedule produced by the model when it optimizes the hydropower plant resource. Future hourly price signals are estimated over the study period by a second Excel spreadsheet referred to as the Spot Price Processor. It uses 2004 hourly spot market price patterns produced by the AURORA model (Electric Power Information Solutions, Inc. 2005), an estimate of historical 2004 market prices for the Palo-Verde market hub as reported in the Dow-Jones index, and a nominal inflation rate.

GTMax results include an estimate of the economic value of Glen Canyon power plant capacity and energy production over the simulation period. It also includes an estimate of the hydropower plant maximum production capability taking into account ROD operational constraints. This measure of capacity is mostly, but not always, substantially less than the physical capability of the plant based only on hydrological head; that is, the physical capability estimated by CRSS.

Western customer power rates are calculated using a power repayment study (PRS) spreadsheet-based computer program that contains both general and specific repayment rules associated with a particular hydropower project. This spreadsheet uses GTMax-Lite results for Glen Canyon and from the full-scale GTMax model for all other Salt Lake City Area Integrated Project (SLCA/IP) plants.

A more detailed explanation of the methodology used for the Shortage Criteria EIS is provided in the following sections. This includes both data processing algorithms and the GTMax-Lite simulation model. Detailed explanations of other models, such as CRSS that feed into the process, but are not run by Western, are provided elsewhere.

CRSS Model

The CRSS model mimics operational decisions that are made for CRSP reservoirs. Since EIS alternatives have unique criteria, each simulation contains alternative-specific operating rules that affect monthly and annual water releases. Monthly release patterns affect the economic value of the hydropower resource since the value of power is highly sensitive to seasonal and hourly variations in market prices. Typically market prices are the highest in the summer and winter seasons. Therefore, from a power generation-centric viewpoint, water releases would ideally be concentrated during these two seasons. However, from a broader perspective power benefits must be weighted against other operational objectives such as flood control, irrigation, municipal and industrial water supplies, recreation, and the environment.

Shortage Criteria alternatives also affect reservoir forebay elevations and the amount of water that bypass turbines. The forebay elevation determines the hydraulic head and is the primary factor that influences the amount of power that is produced per volume of water released through the turbines. High forebay elevations typically translate into more power production per AF of turbine water releases as compared to lower forebay elevations. However, maintaining full or nearly full reservoirs increases the risk of releasing water through bypass tubes and spillways. Sudden unexpected inflows under a full reservoir condition may require reservoir releases that exceed maximum turbine flow rates. Maintaining lower reservoir levels, on the other hand, will reduce the risk of non-turbine water releases during flood conditions, but it will also increase the risk of lowering the forebay elevation below turbine inlet tubes during droughts. When this occurs, both power production and the plant capacity is zero. Operating rules must therefore balance the risks associated with either having too much or not enough water stored in Lake Powell.

Balancing risks in a basin with large variations of water inflows, such as the Colorado, require a full-spectrum examination of hydrological conditions. Therefore, the CRSS model produces numerous simulation results for each month. These results represent a range of plausible futures from which probability distributions of future hydropower conditions are constructed. Distributions are influenced by initial reservoir conditions such that distributions are relatively narrow for near-term projections. This represents a relatively low level of uncertainty about the future. However, as the projection period extends further into the future, the distribution widens as uncertainty grows.

CRSS results include scenario-specific estimates of monthly energy production and physical capability for 100 possible futures throughout the analysis period which extends from the beginning of January 2008 through the end of December 2060. For the Shortage Criteria EIS, forecasts are made by simulating reservoir operations with 100 different sequences of inflows. Each sequence is based on a chronological inflow pattern that has occurred in the past, and is referred to as a trace. Refer to for the text of the EIS for a detailed explanation of CRSS reservoir operating rules and traces.

Hydrological Conditions Studied

Ideally detailed simulations of hourly operations at the Glen Canyon Dam hydropower plant would be performed for each of the 100 traces over the 53-year analysis period. However, it is computationally impractical. Therefore, a simplified approach was used to measure differences among alternatives. This involves analyzing only selected points from the monthly distributions produced by CRSS. The Data Processor spreadsheet computes statistics and extracts pertinent information from the CRSS output.

Western chose five hydrological conditions to study to ensure a representative look at the differences between the alternatives. The five conditions are: Mean, Median, 90 percent Exceedence, 10 percent Exceedence, and Trace 94, and are explained below.

- **Mean:** An average value of the 100 CRSS traces was computed for each month of the study period, for each alternative.
- **Median:** The 50th percentile value of the 100 CRSS traces was computed for each month of the study period, for each alternative.
- **90 percent Exceedence:** The 10th percentile value of the 100 CRSS traces was computed for each month of the study period. 90 percent exceedence is often referred to as 10th percentile in Western and Reclamation hydrological studies; the two terms are synonymous.
- **10 percent Exceedence:** The 90th percentile value of the 100 CRSS traces was computed for each month of the study period. 10 percent exceedence is often referred to as 90th percentile in Western and Reclamation hydrological studies; the two terms are synonymous.
- **Trace 94:** Individual traces of the CRSS output were examined. Trace 94 was selected by Western as representing especially poor conditions for generation at GCD, with periods of no generation due to low Lake Powell reservoir elevations (below 3490’). Trace 94 was selected to examine the difference in performance of the six alternatives under conditions of complete loss of GCD generation for an extended period of time. Trace 94 also allows for examination of a time-connected series of potential GCD operations, showing drops and recoveries of Lake Powell elevation over time. The other four hydrological conditions studied are not time-connected in the same manner that a single trace is.

Mean, median, 90 percent exceedence, and 10 percent exceedence values for capability and energy are computed separately. Furthermore, capability statistics are based only on hydrologic head as computed by CRSS. However, under current operating constraints imposed on Glen Canyon, sustainable capability is a function of both the physical powerplant capability and the monthly water release volume (refer to the next section for more details). Although it may be more accurate to compute capacity statistics using both the hydrologic head and monthly water releases, this process would have been very computationally intensive with only a marginal increase in precision. As a simplification, statistical values for physical capability and energy are first calculated and then sustainable capacity is estimated by the GTMax-Lite model using these statistical values.

Glen Canyon Dam Record of Decision

The economics of Shortage Criteria Alternatives is not only a function of monthly water release volumes, but also of physical and institutional limitations on daily and hourly operations. Of particular importance is the Glen Canyon Dam Record of Decision (ROD) that affirmed the selection of the Modified Low Fluctuating Flow Alternative as the preferred operating alternative. The Bureau of Reclamation (Reclamation) issued the operating criteria for Glen Canyon Dam early in 1997. The 1997 Operating Criteria expanded on the operational rules contained in the Glen Canyon Dam Operation EIS and ROD. It also provided Western and Reclamation staff with guidance on the operation of the dam and the Salt Lake City Area Integrated Projects (SLCA/IP) power system.

The ROD imposed a limit on the maximum allowable release from Glen Canyon Dam to 25,000 cubic feet of water per second (cfs) and included exceptions to the maximum release for Beach/Habitat Building Flows and Habitat Maintenance Flows such as occurred in March 1996. Exceptions were also made to avoid spills or flood flow releases during high runoff years. During high hydropower conditions when the total monthly water release volume is greater than a constant 25,000 cfs release rate throughout the month, the maximum release rate is relaxed. However, releases are restricted to a flat-flow operating regime.

Releases must also be at least 8,000 cfs between the daytime hours of 7:00 a.m. to 7:00 p.m., and 5,000 cfs or more at night. The ROD also set limits on the allowable release fluctuations in any continuous 24-hour period. The amounts vary depending on the volume of water scheduled to be released in a given month. For example, the allowable daily change is 5,000 cfs/24 hours for months in which scheduled water releases through the dam are less than 600 thousand acre feet (TAF). Fluctuations will be held at 6,000 cfs/24 hours for months of scheduled releases between 600 and 800 TAF, and at 8,000 cfs/24 hours for months of scheduled releases greater than 800 TAF/month. Finally, the ROD limits the rate at which the generators may ramp up or down during a 1-hour time period. The maximum power plant ramp rates are set at 4,000 cfs per hour increasing and 1,500 cfs per hour decreasing.

GTMax-Lite Data Processor

The Data Processor spreadsheet prepares input data for the GTMax-Lite model by translating CRSS and ROD information from water units into equivalent power and energy units. Equations that are used by the spreadsheet are summarized in Table 1. For example, the processor multiplies a power conversion factor by the ROD allowable maximum flow rate to compute the maximum power plant output. Power factors are approximated by CRSS for each trace in all study months. The maximum output level computed by the data processor is not always achieved since the maximum daily change restriction and hourly up and down ramp rate limits further constrain operations.

Table 1
Equations for Converting ROD Operating Criteria and CRSS Output

CRSS/ROD Criteria	Power Equivalent for GTMax-Lite Input
Monthly Water Release	$E_w^{pow} = \frac{TR_m^{wat} \times CF_m^{w-p}}{1000} \times \frac{7}{ND_m} \quad \forall \; m \mid m = 1, \ldots, NM$
Maximum Release	$C_w^{pow} = \mathrm{Max}\left(C_m^{CRSS}, \frac{MR_m^{wat} \times CF_m^{w-p}}{1000} \times 0.082644 \right) \quad \forall \; m \mid m = 1, \ldots, NM$
Maximum Daily Change	$DC_w^{pow} = \frac{DC_m^{wat} \times CF_m^{w-p}}{1000} \times 0.082644 \quad \forall \; m \mid m = 1, \ldots, NM$
Hourly Up-Ramp Rate Limit	$HU_w^{pow} = \frac{HU_m^{wat} \times CF_m^{w-p}}{1000} \times 0.082644 \quad \forall \; m \mid m = 1, \ldots, NM$
Hourly Down-Ramp Rate Limit	$HD_w^{pow} = \frac{HD_m^{wat} \times CF_m^{w-p}}{1000} \times 0.082644 \quad \forall \; m \mid m = 1, \ldots, NM$
Minimum Daytime Release	$DM_w^{pow} = \frac{DM_m^{wat} \times CF_m^{w-p}}{1000} \times 0.082644 \quad \forall \; m \mid m = 1, \ldots, NM$
Minimum Nighttime Release	$MN_w^{pow} = \frac{MN_m^{wat} \times CF_m^{w-p}}{1000} \times 0.082644 \quad \forall \; m \mid m = 1, \ldots, NM$

where,

$m =$ Simulation month index

$w =$ Simulation week index with one representative week per month

ND_m = Number of simulation days in month m

NM = Number of simulation months; $636 = 12 \times 53$

$E_w^{pow} =$ Weekly generation (MWh) during week w

$TR_m^{wat} =$ Total water volume (AF) released during month m

$C_w^{pow} =$ Weekly capability (MW) during week w

$C_m^{CRSS} =$ CRSS physical capability (MW) during month m

$MR_m^{wat} =$ Maximum release rate (cfs) during month m; dependent on TR_w^{wat}

$DC_w^{pow} =$ Maximum daily change (MW/day) during week w

$DC_m^{wat} =$ Maximum daily change (cfs/day) during month m; dependent on TR_w^{wat}

$HU_w^{pow} =$ Maximum hourly power increase (MW/h) during week w

$HU_m^{wat} =$ Maximum hourly up-ramp rate (cfs/hr) during month m

$HD_w^{pow} =$ Maximum hourly power decrease (MW/h) during week w

$HD_m^{wat} =$ Maximum hourly down-ramp rate (cfs/hr) during month m

$MD_w^{pow} =$ Minimum daytime hourly generation (MWh) during week w

MD_m^{wat} = Minimum daytime release rate (cfs) during month *m*

MN_w^{pow} = Minimum nighttime hourly generation (MWh) during week *w*

MN_m^{wat} = Minimum nighttime release rate (cfs) during month *m*

It should be noted that the monthly water releases in table are scaled to represent the amount of water that is released in a typical week. GTMax-Lite model is executed for only 1 week per study period month. Total generation during this "typical" week is based on CRSS monthly water release volumes times a scaling factor. This factor is equal to the number of days in the week divided by the number of days in a simulated month. For example, the scaling factor for January equals 7 divided by 31. The inverse of this factor is used to obtain monthly values by scaling-up weekly results.

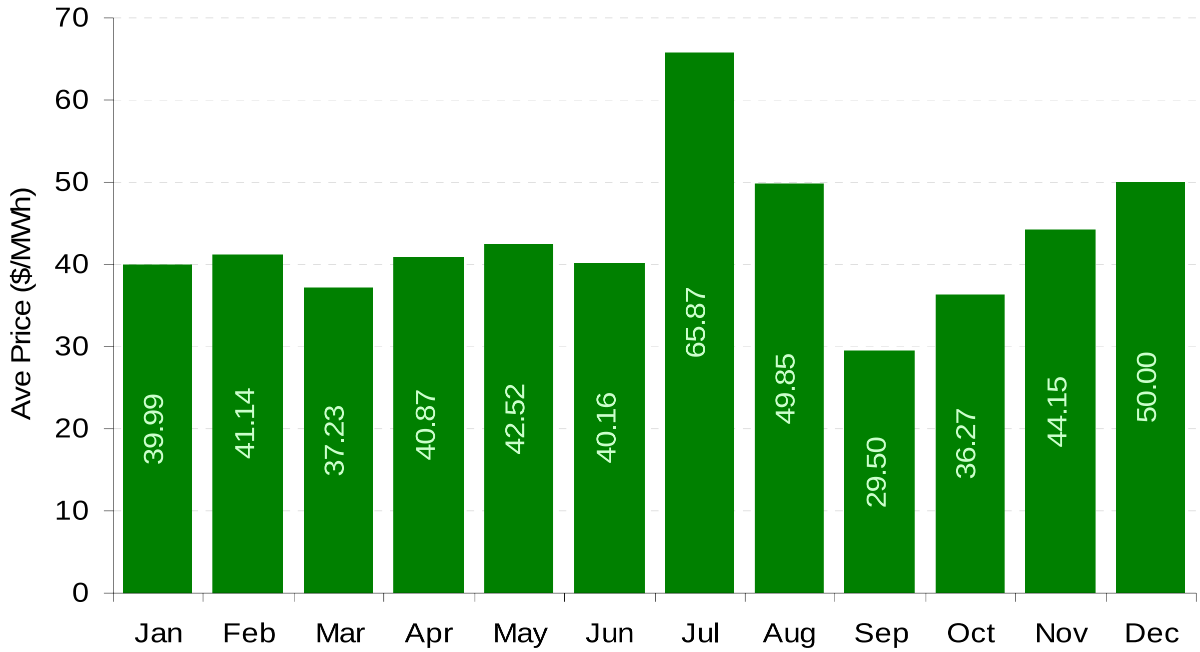
Market Prices

Representative energy and capacity prices are essential for an economic evaluation of Shortage Criteria alternatives. Pricing assumptions tend to be controversial because there are many sources of information, and because the price assumed can make a large difference in the resulting valuation of energy and capacity. Some analysts prefer using historical energy and capacity prices because they can be tied to a specific set of purchase transactions. Others prefer to use estimates of future costs under the assumption that historical costs do not necessarily predict future prices. Prices for historical or future energy can be obtained fairly easily from a variety of sources. However, prices for capacity are more difficult to obtain since they are more closely identified to a particular utility or power generation facility and usually are considered proprietary information by the facility owner.

Western coordinated analysis of energy prices with Reclamation to ensure that both agencies were using the same data. The two agencies agree upon a method that combined two types of energy prices. These data include a historical price index for the Palo-Verde market hub contained in a Dow Jones, Inc. database and hourly market price patterns produced by the AURORA model. Both the historical and modeled data are for the year 2004. Prices for 2005 were rejected from consideration due to the anomalies caused by fuel supply disruptions resulting from hurricane damage that occurred in the summer and autumn.

A review of hourly 2004 Dow Jones price data identified numerous anomalies such as atypically high prices on several Sundays over the course of the year. There were also long and frequent periods of missing data. Although the Dow Jones month average prices, shown in Figure 2, are representative and would suffice for Reclamation's monthly energy modeling, the quality of the hourly price data was inadequate for Western's hourly modeling. To eliminate the hourly energy price problems, Reclamation provided Western with AURORA model simulated market prices for 2004. The Aurora model results had hourly and weekly prices that represented typical weekly price profiles, but average price levels were significantly less than historical levels. To match the Dow Jones index prices, the AURORA hourly model output was scaled such that the average monthly values matched the Dow Jones monthly average values. A more detailed description of the scaling process is provided in the next section.

Figure 2
Average Market Prices for 2004 Based on the Dow Jones Index



Some of the anomalies associated the Dow Jones, Inc. price index may be a reflection of the energy market that is currently functioning in the WECC and small number of reported transactions that is used to calculate the index. For any given hour the Dow index is the weighted average price for all reported bilateral exchanges. A bilateral exchange is a private transaction between two parties at a negotiated price. It should also be noted that only a small percentage of bilateral contracts are reported to the Dow Jones. Although monthly average prices follow a typical pattern, the extent to which the Dow Jones prices reflect the broader WECC electricity market is not known. This method of price discovery differs from a market price that is determined through a central clearinghouse whereby individual buyers and sellers do not directly communicate with each other. Instead a price is determined by the intersection of supply and demand bid curves.

AURORA model simulations used in this analysis were developed for and used in the Northwest Power and Conservation Council's Fifth Northwest Electric Power and Conservation Plan (NWPCC 2005). The Northwest Power and Conservation Council is primarily interested in Northwestern electricity markets. Relatively less attention is devoted to characterizing market conditions in other parts of the WECC region. Consequently, the Palo Verde forecast described in this analysis primarily reflects the default data supplied with the AURORA model.

Market Price Processor

The GTMax-Lite model uses a projection of market prices as a measure of the future economic value of hydropower generation. This assumption implies that market prices reflect the marginal economic cost of serving the last megawatts-hour (MWh) of load in the system (i.e., system lambda). Furthermore, Glen Canyon power injections into the grid are minuscule relative to the entire power system in which it operates. Therefore, its operations do not influence the marginal value of energy. Given the size and complexity of the Western Electricity Coordinating Council (WECC) power grid and the markets that it functions in, these assumptions are reasonable. It should also be noted that the relative economic differences among alternatives are of importance, rather than the absolute economic value of a specific alternative.

The Spot Price Processor prepares typical energy price profiles for GTMax based on the AURORA model results. Instead of using each hourly price, typical spot price patterns were computed for three different day types in each month. These include Sunday, weekday, and Saturday. A daily price pattern is obtained by computing an average hourly price for each similar hour. For example, the weekday price at 1 a.m. is the average of AURORA prices at 1 a.m. for all days in a month that are between Monday and Friday, inclusive. Each day of the month is then assigned hourly prices depending on the month and type of day. For example, every weekday in January is assigned the average price pattern for January weekdays.

The final step of the process scales monthly prices to match the simple (i.e., unweighted) mean of hourly Palo-Verde prices contained in the Dow Jones database. These monthly average prices follow a typical seasonal pattern for the Southwestern United States. Prices are the highest during the summer months reflecting an elevated demand for air conditioning. On the other hand, prices during the spring and autumn seasons are relatively low. Winter prices are somewhat higher than these shoulder seasons as loads are elevated by more lighting and heating demands. Prices are inflated to approximate hourly prices for future years. For this analysis, the annual inflation rate is assumed to be 2.2 percent.

The use of typical (i.e., average) hourly price profiles to estimate Glen Canyon power plant generation patterns is more realistic than estimating generation patterns based on individual hourly prices. This is in part due to the recognition that power marketers have excellent foresight regarding overall daily price patterns over the upcoming week, but the magnitude and individual hourly variations from the typical pattern cannot be accurately predicted. In contrast, the GTMax model has perfect foresight and if provided with the detailed price profile it will react to each individual "perfectly predicted" price. When GTMax is provided with the typical or average pattern, it produces a generation pattern that more closely emulates actual energy scheduling practices.

Market prices have a profound influence on generation schedules prepared by power marketers as well as those produced by optimization models. Figures 3 and 4 show hourly used by GTMax for a winter month, December, and for a summer month, July. The hourly price pattern for weekdays in December follows a typical winter profile with two separate daily peaks. The first peak occurs in the morning followed by a midday price slump. Prices rise again in the evening reaching a high between 6 p.m. to 8 p.m. The lowest prices hours are in the middle of the night, bottoming out at 2 a.m. to 4 a.m. Prices are somewhat lower during the weekends, especially on Sunday. Also weekend hourly price patterns deviate somewhat from weekday price profiles.

While winter prices exhibit a two-hump price pattern, prices during the summer months peak only once during the day – typically in the late afternoon between 4 p.m. to 6 p.m. during the hottest part of the day. Similar to the wintertime, prices are at a minimum in the middle of the night.

GTMax-Lite Model

Western and Argonne National Laboratory simulated Glen Canyon hydropower plant operations on an hourly time step the with the GTMax-Lite modeling software. GTMax-Lite is similar to the full version of the GTMax model except it only contains those features that are required to perform an economic evaluation of Shortage Criteria alternatives. Model run time and data transfers are significantly shorter, while a level of simulation accuracy equivalent to the full version is retained.

The GTMax-Lite objective function is to produce an hourly generation schedule over a one (1) week time period that maximizes the economic value of the hydropower resource. Market prices input into the model convey the economic value of hydropower generation. These prices heavily influence the generation schedule produced by the model when optimizing the hydropower plant resource. To the extent possible the GTMax-Lite model uses its limited energy resource to first generate electricity during on-peak hours when it has the highest economic value. Any remaining energy is scheduled during lower-priced hours.

Glen Canyon power plant operations are subject to a set of constraints. These include a physical operating capability and a limit on the total weekly electricity production. As described in previous sections, these constraints are consistent with CRSS model results. In addition to physical operating constraints, the GTMax-Lite model also complies with the ROD Criteria. Table 2 contains the GTMax-Lite mathematical formulations consisting of an objections function and a set of operating constraints.

Figure 3
December AURORA Prices Scaled to the Dow Jones Monthly Average

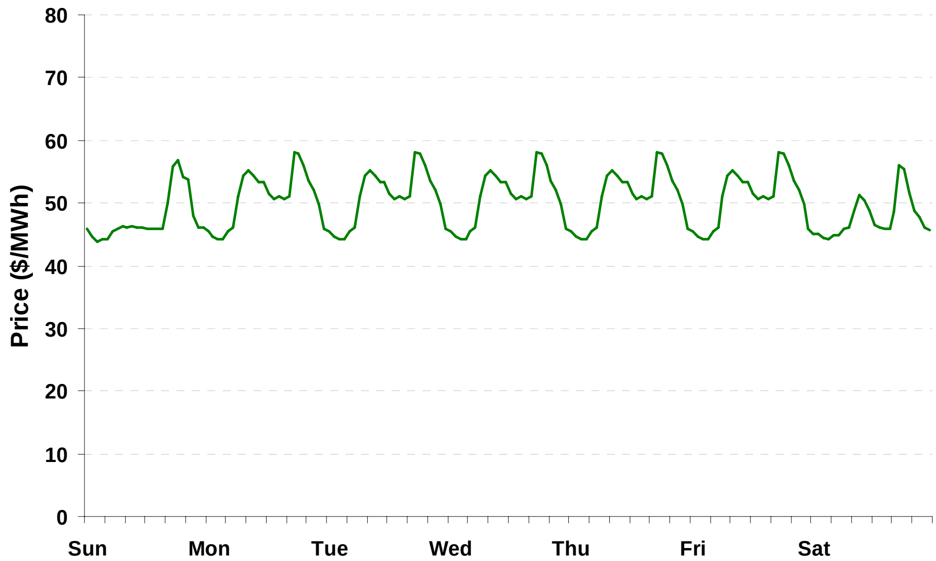


Figure 4
July AURORA Prices Scaled to the Dow Jones Monthly Average

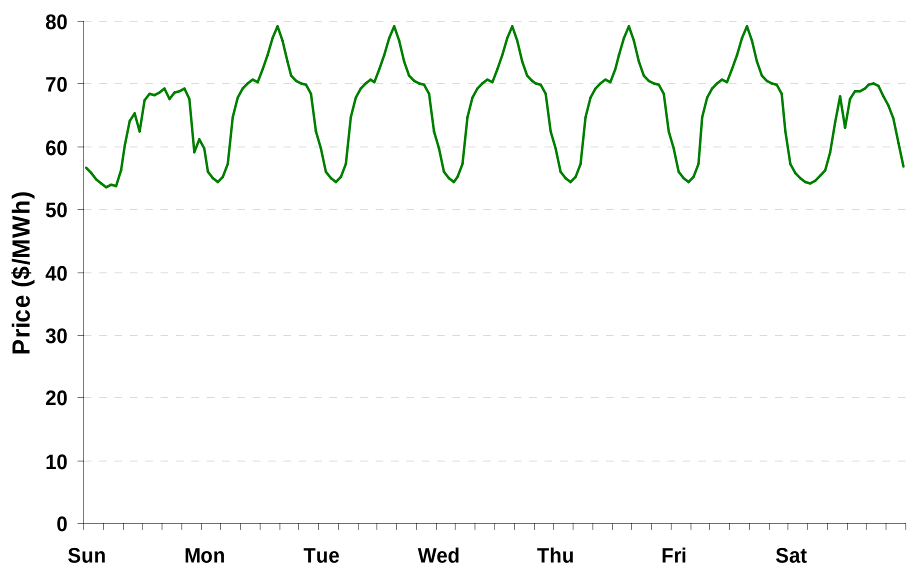


Table 2
GTMax-Lite Equations

Description	GTMax-Lite Equation
Objective Function	$Maximize: \quad SP_h \times Gen_h \quad \forall\ h \mid h = 1,\ldots,168$
Maximum Hourly Generation	$Gen_h \le C_w^{pow} \quad \forall\ h \mid h = 1,\ldots168$
Weekly Generation	$WGen_w = \sum_{h=1}^{168} Gen_h$
Maximum Daily Change	$DC_w^{pow} \ge Gen_{j+k-wrap} - Gen_j \quad \forall\ j \mid j = 1,\ldots,168$ and for each $j,\ k = 1,\ldots,23$ $when\ j+k>168,\ wrap = j+k\text{-}168\ else\ wrap = 0$
Hourly Up-Ramp Rate Limit	$HU_w^{pow} \ge Gen_h\text{-}Gen_{h-1+Wrap} \quad \forall\ h \mid h = 1,\ldots168$ when $h>1$ $wrap = 0$ else $wrap = 168$
Hourly Down-Ramp Rate Limit	$HD_w^{pow} \ge Gen_{h-1+wrap}\text{-}Gen_h \quad \forall\ h \mid h = 1,\ldots168$ when $h>1$ $wrap = 0$ else $wrap = 168$
Minimum Daytime Release	$MD_w^{pow} \le Gen_h \quad \forall\ h \mid h = 1,\ldots,7, 20,\ldots,31, 44,\ldots,55, 68,\ldots,79, 92,\ldots,103, 116,\ldots,127, 140,\ldots,151, 164,\ldots168$
Minimum Nighttime Release	$MN_w^{pow} \le Gen_h \quad \forall\ h \mid h = 8,\ldots,19, 32,\ldots,43, 56,\ldots,67, 80,\ldots,91, 104,\ldots,115, 128,\ldots,139, 152,\ldots,163$
Daily Generation	$DGen_d = \sum_{i=1}^{24} Gen_{(d-1)\times 24+i} \quad \forall d \mid d = 1,\ldots,7$
Minimum Daily Generation for Weekend Days	$DGen_d \ge DGen_2 \times DMin_d \quad \forall d \mid d = 1,7$
Identical Weekday Total Generation Levels	$DGen_2 = DGen_d \quad \forall d \mid d = 3,4,5$

where,

$h =$ Simulation hour index

$d =$ Simulation day index where 1=Sun, 2= Mon, etc.

$wrap =$ index parameter to address temporal boundary conditions

$Gen_h =$ Average generation level (MWh) during hour h

$SP_h =$ Spot market price index ($/MWh) for hour h

$WGen_w =$ Total generation (MWh) during week w

$DGen_d =$ Total generation (MWh) during day d

$DMin_d =$ Minimum daily generation fraction for day d (see Table X)

In practice, hydropower plant operations do not always strictly follow an economic optimization regime as suggested by mathematical models. This occurs because models are a simplification of reality and typically only include those elements that can be described in the form of in mathematical equations. In GTMax-Lite, equations are used to model the power plant based on an economic maximization function subject to physical and legal operating limits. However, marketers must often include other important factors which result in operations that often deviate from the simplified mathematical optimal. Some of these factors include individual risk tolerance levels and intricacies associated with bilateral contracts, block spot purchase patterns, grid limitations, and power exchanges and interchanges. Other factors not included in GTMax-Lite are general agreements that have been made with affected parties, but that are not contained in a legally binding decree.

Despite its limitations, the GTMax-Lite model usually simulates daily and hourly generation patterns that are similar to actual operations. However, compared typical operations, the GTMax-Lite model will at times schedule less power during the weekend when market prices are low, shifting more power to higher-priced weekdays. Although operations comply with ROD constraints, the GTMax-Lite schedule may have some detrimental implications for the environment. Therefore, additional constraints that specify a minimum allocation of daily generation among the days of the weeks are incorporated into the GTMax-Lite mathematical formulation.

Daily minimums are specified as the ratio of daily generation during a weekend day relative to the average daily generation during a weekday. For example, a value of 0.9 assigned to Saturday requires that the total generation during that day must be at least 90 percent of a weekday’s generation. Values assigned to the daily generation restrictions are based on historical operations and vary by month as shown in Table 3. Minimum daily generation levels are often not binding in the model and water releases scheduled by GTMax-Lite on Saturday and Sunday frequently are more than the minimum.

Table 3
Daily Generation Fractions for Weekend Days

Month	Sunday	Saturday
January	0.86349	0.88511
February	0.86861	0.94269
March	0.90666	0.94367
April	0.91358	0.98481
May	0.93182	0.95657
June	0.86247	0.89126
July	0.94368	0.96479
August	0.92117	0.94085
September	0.95205	0.96890
October	0.97621	0.97621
November	0.94810	0.98237
December	0.90623	0.96419

Glen Canyon power plant operations simulated by GTMax-Lite under median hydrological conditions for a typical week in the wintertime, 2nd week in December, 2010, are depicted in Figure 5. To maximize the economic value of the hydropower resource, the model generates as much power as possible during hours when market prices are the highest. Generation tends to drop as the spot price decreases; for example, during the midday price valley. Generation during on-peak hours are constrained by the ROD daily change, reaching a peak of about 610 megawatts (MW). That is substantially less than (approximately half) the median capability of 1,205 megawatts (MW) estimated by CRSS based on the Powell Reservoir forebay elevation.

Simulated operations during the summertime also tend to follow prices. As shown in Figure 6, Glen Canyon generation exhibits a one-hump pattern that has a shape similar to the market price profile. Simulated operations are for July 2010 under median conditions. Comparable to the wintertime, peak generation levels are constrained to slightly more than 600 megawatts (MW) despite a hydrological head that is capable of supporting generation levels of approximately 1,232 MW.

Figure 5
Glen Canyon Power Plant Operations under Median Winter Conditions

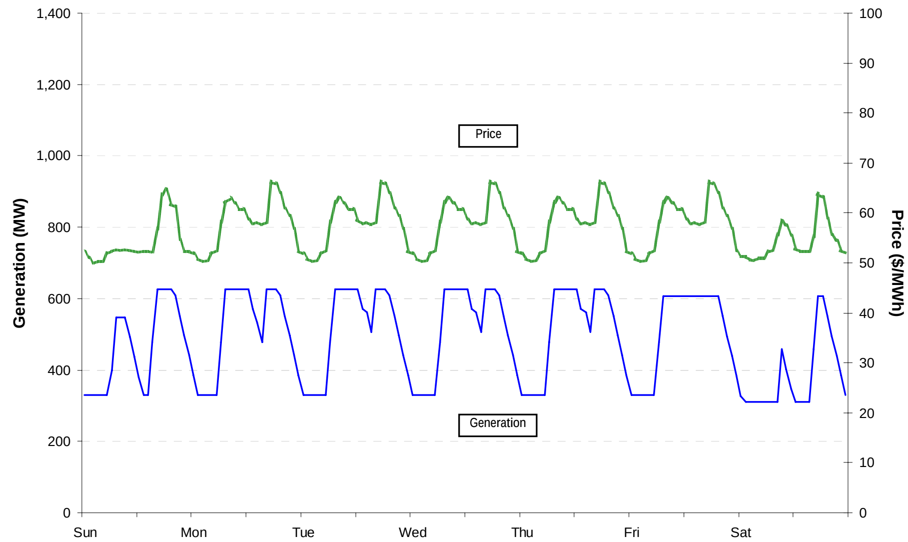
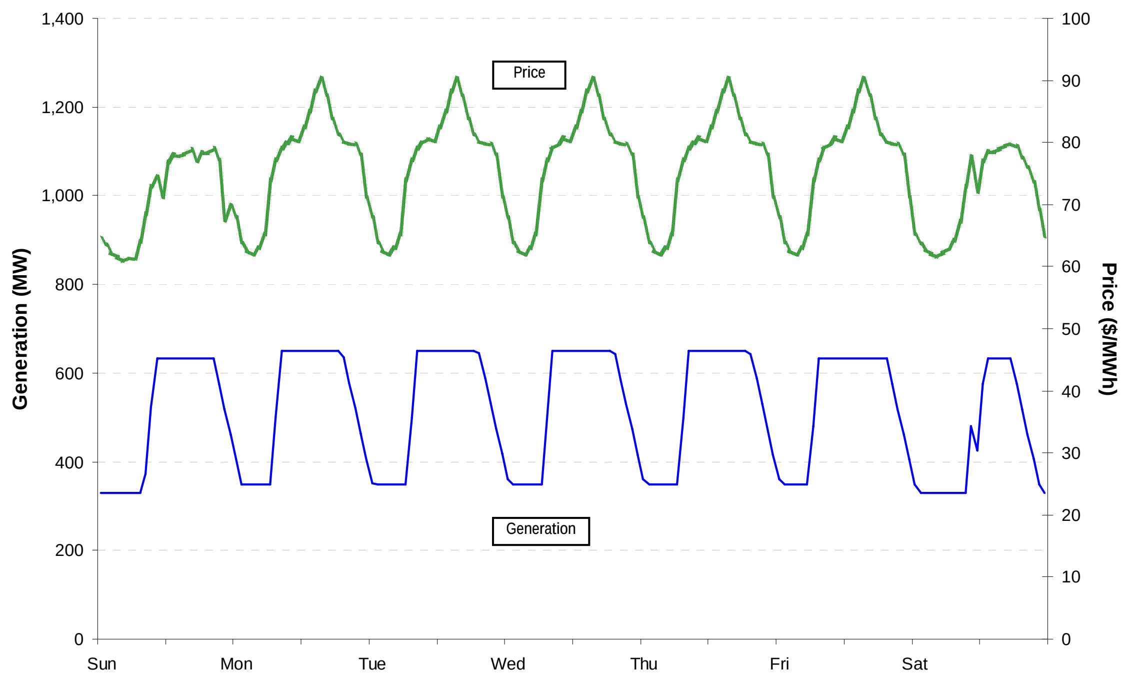
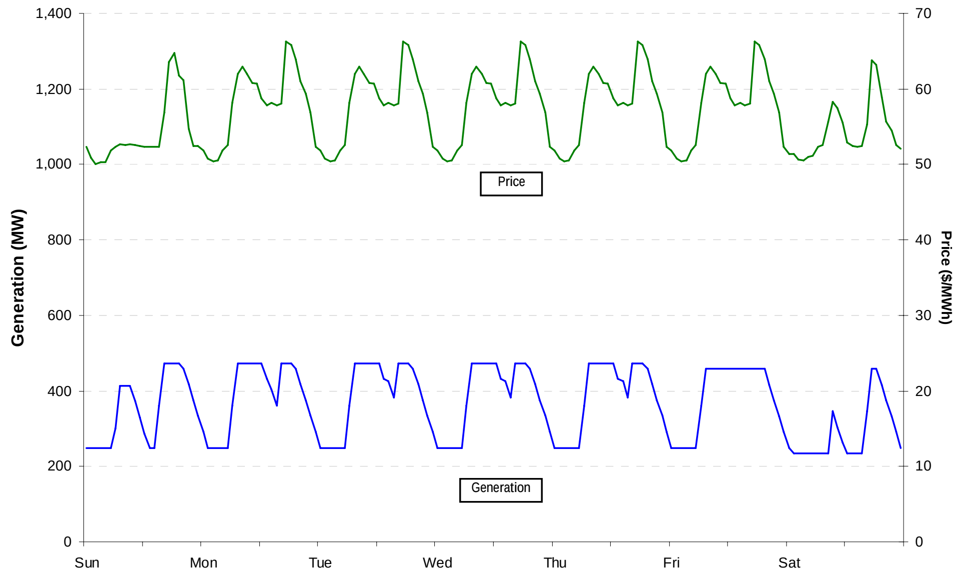


Figure 6
Glen Canyon Power Plant Operations under Median Summer Conditions



Under dry hydrological conditions, the maximum generation levels simulated by GTMax-Lite drop even further. Figure 7 shows that on-peak production levels are less than 475 MW. Under the driest conditions, forebay elevations dip below turbine water inlet tubes resulting in zero monthly electricity generation and zero power plant capacity.

Figure 7
Glen Canyon Power Plant Operations under Dry Winter Conditions



Economic Calculations

The economic value of the Glen Canyon Dam energy is computed by multiplying power plant generation estimated by GTMax-Lite by the market price. Since the model only simulates operations for one representative week in each month, economic values are scaled. This scaling factor equals the number of days in a projection month divided by 7. A net present value (NPV) of the monthly economic values over the study period was calculated by discounting monthly values at an annual rate of 4.875 percent. When discounting, it was assumed that the stream of hourly economic benefits in a month occurred mid-month as a single lump-sum value.

Differences in annual energy and capacity generation were calculated between the No Action Alternative and each Action Alternative. The annual capacity difference in terms of megawatts was assigned a value using a capacity price of $6.32/kilowatt-month. That price represents the market value of generation in 2007 dollars. For valuing capacity, Western obtained a cost of constructing a new combined cycle natural gas power plant. Capacity was valued at the replacement cost identified by some SLCA/IP customer utilities who have recently constructed facilities which provide load following capacity. These customer data were collected in order to get information regarding the construction cost per megawatt of a recently built facility that provides electrical services similar to the GCD power plant.

This value is higher than the average cost of capacity from existing facilities on the system, but was selected for two reasons. (1) Over the 53-year study period, available capacity from existing sources will not be adequate to serve growing loads. New capacity will have to be built. (2) Renewable resource requirements in states such as California could cause new capacity costs to escalate at a rate faster than the 2.2 percent assumed in this analysis.

The two Western offices performing analyses coordinated capacity values, so the same capacity values were used for GCD and for the Lower Basin power plants.

Capacity values were converted to a present value using the same method as for energy, and were then added to the energy present value to obtain a total value of the difference in generation between the No Action alternative and each Action alternative. Reclamation did not value capacity differences in their analysis.

Results of Western's Analysis

Western Area Power Administration's financial analysis of the alternatives concentrated on the effect each alternative has on energy generation and capacity generation at Glen Canyon Dam (GCD). The effects are measured by the difference in generation in gigawatthours (GWh) of energy and megawatts (MW) of capacity between the No Action alternative and each of the Action alternatives, for the five representative hydrological conditions outlined above. The analysis includes the economic effect of changes to capacity and energy calculated by applying energy and capacity costs to the changes in generation. Finally, a net present value calculation was performed to develop a single value to compare each Action alternative to No Action. The sections below break down the results of the analysis into each of the aspects studied.

Glen Canyon Dam Energy Generation

The energy generation at GCD for each alternative was summed over the 53-year study (2008-2060) period and is displayed in Table 4 below in GWh. (One GWh is equal to 1 million kilowatt hours.) The difference in generation of the Action alternatives as compared to No Action is shown in Table 5. Table 6 has those same differences as percentages.

Table 4
Energy Generation

Alternatives	Mean (GWh)	Median (GWh)	90% Exceed. (GWh)	Trace 94 (GWh)	10% Exceed. (GWh)
No Action	4,247.88	3,748.42	3,130.88	4,300.57	6,312.73
Basin States	4,244.28	3,799.64	3,038.20	4,419.71	6,274.71
Conservation Before Shortage	4,244.89	3,798.99	3,037.97	4,420.09	6,276.28
Water Supply	4,138.76	3,783.26	2,904.22	4,366.65	6,214.02
Reservoir Storage	4,281.05	3,768.78	3,134.48	4,320.29	6,374.22
Preferred Alternative	4,251.34	3,794.67	3,055.75	4,420.69	6,286.12

Table 5
Change in Energy Generation

Alternatives	Mean (GWh)	Median (GWh)	90% Exceed. (GWh)	Trace 94 (GWh)	10% Exceed. (GWh)
No Action	0.00	0.00	0.00	0.00	0.00
Basin States	(3.61)	51.21	(92.68)	119.14	(38.02)
Conservation Before Shortage	(2.99)	50.57	(92.91)	119.52	(36.45)
Water Supply	(109.12)	34.83	(226.66)	66.08	(98.71)
Reservoir Storage	33.17	20.36	3.60	19.71	61.49
Preferred Alternative	3.46	46.25	(75.13)	120.12	(26.61)

Table 6
Percent Change in Energy Generation

Alternatives	Mean (percent)	Median (percent)	90% Exceed. (percent)	Trace 94 (percent)	10% Exceed. (percent)
No Action	0.00%	0.00%	0.00%	0.00%	0.00%
Basin States	-0.06%	0.97%	-2.11%	2.06%	-0.44%
Conservation Before Shortage	-0.05%	0.96%	-2.12%	2.06%	-0.42%
Water Supply	-1.84%	0.66%	-5.17%	1.14%	-1.13%
Reservoir Storage	0.56%	0.39%	0.08%	0.34%	0.71%
Preferred Alternative	0.06%	0.88%	-1.71%	2.07%	-0.31%

Glen Canyon Dam Capacity Generation

Generation of capacity at GCD was calculated and averaged over the same study period as shown in Table 7. The numbers in the table represent the average peak capacity output of GCD in megawatts, and is much lower than the power plant capability based on lake elevation. Table 8 displays the difference between each alternative and the No Action alternative. Table 9 has those same differences as percentages.

Table 7
Average Capacity Generation

Alternatives	Mean (Megawatts)	Median (Megawatts)	90% Exceed. (Megawatts)	Trace 94 (Megawatts)	10% Exceed. (Megawatts)
No Action	606.21	546.21	450.85	598.68	838.76
Basin States	605.33	552.25	435.73	616.66	837.98
Conservation Before Shortage	605.43	552.31	435.84	616.57	838.03
Water Supply	589.72	549.92	416.94	608.19	829.11
Reservoir Storage	611.02	549.08	448.30	600.51	845.51
Preferred Alternative	606.40	551.71	438.44	616.30	839.00

Table 8
Change in Capacity Generation

Alternatives	Mean (Megawatts)	Median (Megawatts)	90% Exceed. (Megawatts)	Trace 94 (Megawatts)	10% Exceed. (Megawatts)
No Action	0.00	0.00	0.00	0.00	0.00
Basin States	(0.88)	6.04	(15.12)	17.97	(0.79)
Conservation Before Shortage	(0.79)	6.09	(15.01)	17.88	(0.74)
Water Supply	(16.50)	3.71	(33.91)	9.51	(9.65)
Reservoir Storage	4.81	2.87	(2.55)	1.83	6.75
Preferred Alternative	0.18	5.49	(12.41)	17.62	0.24

Table 9
Percent Change in Capacity Generation

Alternatives	Mean (percent)	Median (percent)	90% Exceed. (percent)	Trace 94 (percent)	10% Exceed. (percent)
No Action	0.00%	0.00%	0.00%	0.00%	0.00%
Basin States	-0.01%	0.11%	-0.34%	0.31%	-0.01%
Conservation Before Shortage	-0.01%	0.12%	-0.34%	0.31%	-0.01%
Water Supply	-0.28%	0.07%	-0.77%	0.16%	-0.11%
Reservoir Storage	0.08%	0.05%	-0.06%	0.03%	0.08%
Preferred Alternative	0.00%	0.10%	-0.28%	0.30%	0.00%

Present Value of Energy

The NPV of energy generation at GCD was calculated for each Alternative at each hydrological condition. Each of the Action alternatives was compared to the No Action alternative to determine the difference in NPV of energy generation in GWh over the study period. Table 10 shows the NPV of each alternative studied. Table 11 displays the difference between each of the Action alternatives and the No Action alternative. Table 12 has those same differences as percentages.

Table 10
Present Value of Energy

Alternatives	Mean ($ million)	Median ($ million)	90% Exceed. ($ million)	Trace 94 ($ million)	10% Exceed. ($ million)
No Action	$5,939.86	$5,252.65	$4,386.68	$5,795.48	$8,714.88
Basin States	$5,940.86	$5,358.48	$4,215.65	$6,060.69	$8,653.00
Conservation Before Shortage	$5,941.74	$5,356.91	$4,215.84	$6,063.47	$8,655.34
Water Supply	$5,806.84	$5,347.08	$4,040.81	$5,969.16	$8,583.61
Reservoir Storage	$5,992.13	$5,286.84	$4,362.82	$5,844.29	$8,806.41
Preferred Alternative	$5,950.84	$5,345.64	$4,242.91	$6,062.95	$8,669.97

Table 11
Change in Present Value of Energy

Alternatives	Mean ($ million)	Median ($ million)	90% Exceed. ($ million)	Trace 94 ($ million)	10% Exceed. ($ million)
No Action	$0.00	$0.00	$0.00	$0.00	$0.00
Basin States	$1.01	$105.83	($171.03)	$265.22	($61.88)
Conservation Before Shortage	$1.88	$104.26	($170.84)	$267.99	($59.54)
Water Supply	($133.02)	$94.43	($345.87)	$173.68	($131.27)
Reservoir Storage	$52.27	$34.18	($23.86)	$48.81	$91.53
Preferred Alternative	$10.99	$92.99	($143.77)	$267.48	($44.91)

Table 12
Percent Change in Present Value of Energy

Alternatives	Mean (percent)	Median (percent)	90% Exceed. (percent)	Trace 94 (percent)	10% Exceed. (percent)
No Action	0.00%	0.00%	0.00%	0.00%	0.00%
Basin States	0.02%	2.01%	-3.90%	4.58%	-0.71%
Conservation Before Shortage	0.03%	1.98%	-3.89%	4.62%	-0.68%
Water Supply	-2.24%	1.80%	-7.88%	3.00%	-1.51%
Reservoir Storage	0.88%	0.65%	-0.54%	0.84%	1.05%
Preferred Alternative	0.18%	1.77%	-3.28%	4.62%	-0.52%

Present Value of Capacity and Energy and Capacity Combined

Tables 14 and 15 display the combined change in NPV of energy and capacity shown in Table 13 below in dollars and percent, respectively. Tables 16 and 17 display the change in capacity as compared to the values displayed in Table 10 above, respectively.

Table 13
Present Value of Energy and Capacity

Alternatives	Mean ($ million)	Median ($ million)	90% Exceed. ($ million)	Trace 94 ($ million)	10% Exceed. ($ million)
No Action	$7,350.02	$6,522.54	$5,435.79	$7,136.61	$10,663.23
Basin States	$7,351.72	$6,649.12	$5,223.01	$7,464.80	$10,602.68
Conservation Before Shortage	$7,352.88	$6,647.62	$5,223.62	$7,467.32	$10,605.33
Water Supply	$7,184.30	$6,634.62	$5,009.62	$7,344.81	$10,511.84
Reservoir Storage	$7,414.74	$6,564.24	$5,400.48	$7,192.02	$10,771.63
Preferred Alternative	$7,364.28	$6,633.98	$5,257.20	$7,465.98	$10,622.62

Table 14
Change in Present Value of Energy and Capacity

Alternatives	Mean ($ million)	Median ($ million)	90% Exceed. (($ million)	Trace 94 ($ million)	10% Exceed. ($ million)
No Action	$0.00	$0.00	$0.00	$0.00	$0.00
Basin States	$1.70	$126.57	($212.78)	$328.19	($60.55)
Conservation Before Shortage	$2.86	$125.07	($212.17)	$330.72	($57.90)
Water Supply	($165.72)	$112.08	($426.17)	$208.20	($151.39)
Reservoir Storage	$64.72	$41.70	($35.31)	$55.42	$108.40
Preferred Alternative	$14.26	$111.43	($178.60)	$329.37	($40.61)

Table 15
Percent Change in Present Value of Energy and Capacity

Alternatives	Mean (percent)	Median (percent)	90% Exceed. (percent)	Trace 94 (percent)	10% Exceed. (percent)
No Action	0.00%	0.00%	0.00%	0.00%	0.00%
Basin States	0.02%	1.94%	-3.91%	4.60%	-0.57%
Conservation Before Shortage	0.04%	1.92%	-3.90%	4.63%	-0.54%
Water Supply	-2.25%	1.72%	-7.84%	2.92%	-1.42%
Reservoir Storage	0.88%	0.64%	-0.65%	0.78%	1.02%
Preferred Alternative	0.19%	1.71%	-3.29%	4.62%	-0.38%

Table 16
Change in Present Value of Capacity

Alternatives	Mean ($ million)	Median ($ million)	90% Exceed. ($ million)	Trace 94 ($ million)	10% Exceed. ($ million)
No Action	$0.00	$0.00	$0.00	$0.00	$0.00
Basin States	$0.69	$20.74	($41.75)	$62.97	$1.33
Conservation Before Shortage	$0.98	$20.81	($41.34)	$62.73	$1.64
Water Supply	($32.69)	$17.65	($80.30)	$34.52	($20.12)
Reservoir Storage	$12.45	$7.52	($11.45)	$6.60	$16.87
Preferred Alternative	$3.28	$18.44	($34.83)	$61.90	$4.30

Table 17
Percent Change in Present Value of Capacity

Alternatives	Mean (percent)	Median (percent)	90% Exceed. (percent)	Trace 94 (percent)	10% Exceed. (percent)
No Action	0.00%	0.00%	0.00%	0.00%	0.00%
Basin States	0.01%	0.39%	-0.95%	1.09%	0.02%
Conservation Before Shortage	0.02%	0.40%	-0.94%	1.08%	0.02%
Water Supply	-0.55%	0.34%	-1.83%	0.60%	-0.23%
Reservoir Storage	0.21%	0.14%	-0.26%	0.11%	0.19%
Preferred Alternative	0.06%	0.35%	-0.79%	1.07%	0.05%

Impact to Western Area Power Administration’s SLCA/IP Firm Power Rate

Western performed a rate analysis of the present value results summarized in Table 13 above. Table 18 shows the results of the analysis on the SLCA/IP firm power rate, while Table 19 shows the difference of each alternative as compared to the No Action alternative, both in mills/kWh and in percent change. Because of time constraints, the rate analysis was confined to the Median and 90 percent exceedence hydrological conditions. (The 90 percent exceedence No Action SLCA/IP rate is a cursory study meant to illustrate the higher rate at low hydrologic levels. It shouldn’t be mis-interpreted as the result of a thorough rate PRS.) An explanation of the methodology Western used to perform the rate analysis is presented below in Tables 18 and 19.

Table 18
SLIP Firm Power Rate

Alternatives	Median (Mill/kWh)	90% Exceed. (Mill/kWh)
No Action	25.28	27.34
Basin States	23.39	31.17
Conservation Before Shortage	23.41	31.17
Water Supply	23.17	30.83
Reservoir Storage	24.89	29.01
Preferred Alternative	23.65	31.17

Table 19
Change in SLIP Firm Power Rate

Alternatives	Median (Mill/kWh)	Median (percent)	90% Exceed. (Mill/kWh)	90% Exceed. (percent)
No Action	0.00	0.00%	0.00	0.00%
Basin States	(1.89)	-7.48%	3.83	14.01%
Conservation Before Shortage	(1.87)	-7.40%	3.83	14.01%
Water Supply	(2.11)	-8.35%	3.49	12.77%
Reservoir Storage	(0.39)	-1.54%	1.67	6.11%
Preferred Alternative	(1.63)	-6.45%	3.83	14.01%

Customer Rates

Western sets rates for firm electric service from Federal hydropower projects in its marketing territory based on Department of Energy regulations and applicable Federal statutes. Power rates are calculated using what is referred to as a power repayment study. The PRS is a special spreadsheet-based computer program that contains the general and any specific repayment rules associated with a particular hydro project such as the SLCA/IP. (The SLCA/IP comprises the Colorado River Storage Project [CRSP], Rio Grande, Collbran, Dolores, and Seedskadee Projects, consolidated for marketing and ratemaking purposes.) When coupled with pertinent project historical data and future projections, the PRS calculates the power rate that is charged to customers who receive SLCA/IP power. The PRS ensures that all identified project costs are repaid within the time frames established by law and regulation.

For the rate analysis work done for this report, two base case PRS's were developed. The two base cases correspond to the power rates for the No Action alternatives at Median and 90 percent Exceedence hydrological conditions. The first is basically the same as the PRS Western used for its current firm power rate. This case is based on Median hydrological conditions, meaning that it includes firming purchase cost estimates for future years based on Median generation estimates. The second base case is the same as the first, except that future firming purchase estimates are based on 90 percent exceedence (10th percentile) estimates of future generation, and firming purchases.

These two base case PRS's produce a rate of 25.28 mills per KWh (Median) and 27.34 mills per KWh (90 percent exceedence). Once the base case PRS's are done, the difference in NPV dollars of each Action alternative as compared to the No Action alternative is inserted into the PRS's and a change in the power rate is computed. These PRS results are what are displayed in Tables 5 and 5a above.

Discussion of Results

Overall, at all hydrological conditions, the Reservoir Storage alternative provides the most favorable conditions for power at GCD, while the Water Supply alternative provides the worst results for power generation, based on the above financial analysis. The Basin States, and Conservation Before Shortage alternatives and the Preferred Alternative show similar results and are ranked between the Reservoir Storage alternative and the Water Supply alternative in their effect on power resources at GCD.

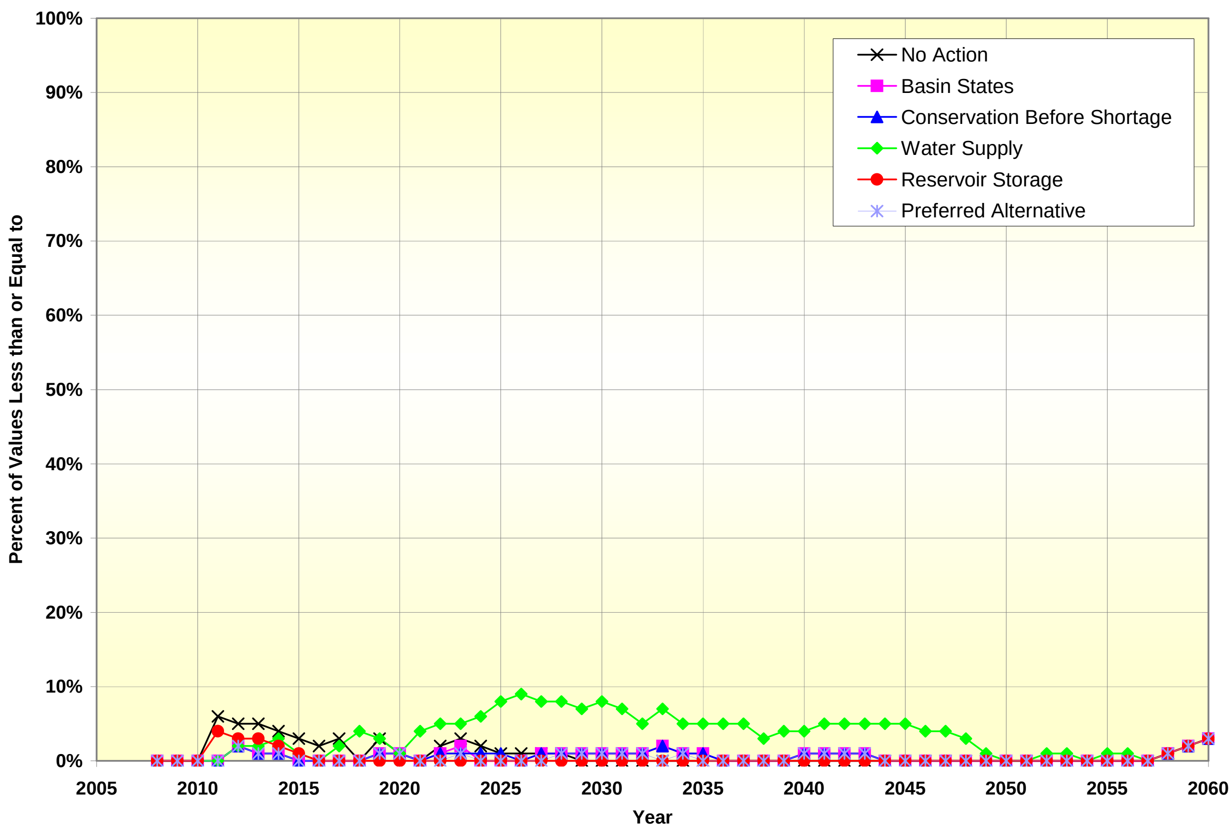
One result is common to Table 19 as well in the preceding tables. At 90 percent exeedence level, the Action Alternatives show consistently worse results (lower energy and capacity generation, lower NPV, higher SLCA/IP rate) than the No Action alternative. Likewise, at Median conditions, the Action alternatives show better results than the No Action alternative. Results at the Mean conditions are more mixed, with some results being better under No Action, and others at one or more of Action alternatives. Trace 94 shows consistent improvement in results of the Action alternatives as compared to No Action. The 10 percent exceedence cases show a lower present value in four of the five alternatives as compared to the No Action alternative, with only the Reservoir Storage alternative showing improvement. At the high levels of generation and revenues represented in the 10 percent exceedence case, the loss of generation in the action alternatives as compared to the No Action alternative is inconsequential to SLCA/IP financial health.

The practical effect of Action alternatives is to produce a widening effect on power generation, revenues, and rates as hydrological conditions range from wet to dry and back to wet. As conditions get drier, generation drops more under the Action alternatives as compared to No Action. Conversely, as conditions go from drier to wetter, generation improves more under the Action alternatives as compared to No Action. This could result in more variation in the CRSP Basin Fund cash reserves, and could lead to additional actions, such as power rate adjustments, rate surcharges, or reductions to customer allocations to respond to shortfalls in revenue under dry conditions. Under the Action alternatives, Western and its power customers would need to quickly respond to changing hydrological conditions to forestall financial problems.

Notwithstanding the financial analysis discussed above, the most important aspect of any of the Action alternatives to Western and the firm power customers is whether and how much the alternative reduces the probability of a total loss of generation from GCD. Loss of GCD generation would result in a huge loss of revenue to Western, Reclamation, and various environmental programs in the Upper Basin; loss of generation and replacement costs for power customers; and degradation to power system reliability.

Figure 8 on the following page is a graph showing the percentage of trace monthly elevations from Reclamation's CRSS modeling output that are less than or equal to elevation 3490'. This graph is an indicator of how well each alternative is able to forestall a shutdown of GCD generation as compared to the No Action alternative.

Figure 8
Lake Powell End-of-March Elevations
Comparison of Action Alternatives to No Action Alternative
Percent of Values Less than or Equal to Elevation 3,490 feet msl



Using this measure, the Water Supply alternative is worse than the No Action alternative, while the Reservoir Storage, Basin States, and Conservation before Shortage alternatives and the Preferred Alternative are equal to or better than No Action.

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