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ANL/DIS-11-4

Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 2006 through 2010

Decision and Information Sciences Division

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Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 2006 through 2010

by
L.A. Poch,[1] T.D. Veselka,[1] C.S. Palmer,[2] S. Loftin,[2] and B. Osiek[2]
[1] Center for Energy, Environmental, and Economic Systems Analysis
Decision and Information Sciences Division, Argonne National Laboratory
[2] Western Area Power Administration, Colorado River Storage Project
Management Center, Salt Lake City, Utah

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FOREWORD

This report was prepared by Argonne National Laboratory (Argonne) in support of a financial analysis of experimental releases from the Glen Canyon Dam (GCD) conducted for the U.S. Department of Energy's Western Area Power Administration (Western). Western markets electricity produced at hydroelectric facilities operated by the Bureau of Reclamation. The facilities known collectively as the Salt Lake City Area Integrated Projects include dams equipped for power generation on the Colorado, Green, Gunnison, and Rio Grande rivers and on Plateau Creek in the states of Arizona, Colorado, New Mexico, Utah, and Wyoming.

This report presents detailed findings of studies conducted by Argonne related to a financial analysis of experimental releases conducted periodically at the GCD from 2006 through 2010. A report issued in January 2011 (ANL/DIS-11-1) performed a financial analysis of experimental releases conducted from 1997 to 2005. Staff members of Argonne's Decision and Information Sciences Division prepared this technical memorandum with assistance from staff members of Western's Colorado River Storage Project Management Center.

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ACRONYMS AND ABBREVIATIONS

The following is a list of the acronyms and abbreviations (including units of measure) used in this document.

AHP	available hydropower
APSF	Aerial Photography Steady Flow
Argonne	Argonne National Laboratory
EIS	Environmental Impact Statement
FSF	Fall Steady Flow
GCD	Glen Canyon Dam
GCDEIS	Glen Canyon Dam Environmental Impact Statement
GTMax	Generation and Transmission Maximization
HFE	High Flow Experiment
MSR	Minimum Schedule Requirement
PO&M-59	Power Operations and Maintenance, Form 59 (a Bureau of Reclamation form entitled, *Monthly Report of Power Operations – Powerplants*)
Reclamation	Bureau of Reclamation
ROD	Record of Decision
SHP	sustainable hydropower
SLCA/IP	Salt Lake City Area Integrated Projects
Western	Western Area Power Administration
WY	water year

UNITS OF MEASURE

cfs	cubic feet per second
ft	feet
hr	hour
MAF	million-acre feet
MW	megawatts
MWh	megawatt-hour(s)
pf	power factor
TAF	thousand-acre feet

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L.A. Poch, T.D. Veselka, C.S. Palmer,* S. Loftin,* and B. Osiek*

ABSTRACT

Because of concerns about the impact that Glen Canyon Dam (GCD) operations were having on downstream ecosystems and endangered species, the Bureau of Reclamation (Reclamation) conducted an Environmental Impact Statement (EIS) on dam operations (DOE 1996). New operating rules and management goals for GCD that had been specified in the Record of Decision (ROD) (Reclamation 1996) were adopted in February 1997. In addition to issuing new operating criteria, the ROD mandated experimental releases for the purpose of conducting scientific studies. A report released in January 2011 examined the financial implications of the experimental flows that were conducted at the GCD from 1997 to 2005. This report continues the analysis and examines the financial implications of the experimental flows conducted at the GCD from 2006 to 2010.

An experimental release may have either a positive or negative impact on the financial value of energy production. This study estimates the financial costs of experimental releases, identifies the main factors that contribute to these costs, and compares the interdependencies among these factors. An integrated set of tools was used to compute the financial impacts of the experimental releases by simulating the operation of the GCD under two scenarios, namely, (1) a baseline scenario that assumes both that operations comply with the ROD operating criteria and the experimental releases that actually took place during the study period, and (2) a "without experiments" scenario that is identical to the baseline scenario of operations that comply with the GCD ROD, except it assumes that experimental releases did not occur.

The Generation and Transmission Maximization (GTMax) model was the main simulation tool used to dispatch GCD and other hydropower plants that comprise the Salt Lake City Area Integrated Projects (SLCA/IP). Extensive data sets and historical information on SLCA/IP powerplant characteristics, hydrologic conditions, and Western Area Power Administration's (Western's) power purchase prices were used for the simulation. In addition to estimating the financial impact of experimental releases, the GTMax model was also used to gain insights into the interplay among ROD operating criteria, exceptions that were made to criteria to accommodate the experimental releases, and Western operating practices.

Experimental releases in some water years resulted in financial benefits to Western while others resulted in financial costs. During the study period, the total financial costs of all experimental releases were more than $4.8 million.

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* C.S. Palmer, S. Loftin, and B. Osiek are employed by Western Area Power Administration Colorado River Storage Project Management Center, Salt Lake City, Utah.

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1 INTRODUCTION

The Glen Canyon Dam's (GCD's) hydroelectric power plant, the Glen Canyon Powerplant (or the Powerplant), consists of eight generating units with a continuous operating capacity of 1,320 megawatts (MW) at unity power factor (pf). At the typical operating point of 0.99 pf, the capacity is slightly less (Seitz 2004). Historically, the plant has operated at a 0.99 pf (Veselka et al. 2010). The Powerplant's electricity production serves the demands of 5.8 million consumers in 10 western states that are located in the Western Electricity Coordinating Council region of the North American Electric Reliability Corporation. Except for a minimum water release requirement at GCD, daily and hourly operations of the dam initially were restricted only by the physical limitations of the dam structures, the Powerplant, and its storage reservoir, Lake Powell. This approach — of adjusting the Powerplant's output principally in response to market price signals — often resulted in large fluctuations in the Powerplant's energy production and associated water releases.

Concerns about the impact of GCD operations on downstream ecosystems and endangered species, including those in Grand Canyon National Park, prompted the Bureau of Reclamation (Reclamation) to conduct a series of research releases from June 1990 to July 1991 as part of an environmental studies program. On the basis of an analysis of these releases, Reclamation imposed operational flow constraints on August 1, 1991 (Western 2010). These constraints were in effect until February 1997, when new operational rules and management goals specified in the Glen Canyon Dam Environmental Impact Statement (GCDEIS) Record of Decision (ROD) were adopted (Reclamation 1996). The ROD operational criteria limit the maximum and minimum amounts of water released from the dam during a one-hour period. The ROD criteria also constrain adjustments in water releases in consecutive hours and restrict the range of hourly releases on a rolling 24-hour basis.

The Glen Canyon Dam Adaptive Management Program, established by the GCDEIS ROD (Reclamation 1996), conducts scientific studies on the relationship between dam operations and downstream resources. Experimental water releases are performed periodically to monitor river conditions, conduct specific studies, enhance native fish habitat, and conserve fine sediment in the Colorado River corridor in Grand Canyon National Park.

During a study period from 1997 through 2005, various types of experiments were performed. Financial costs of those experiments were reported in the document, *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011).

Experiments continue to be conducted at the GCD. This report discusses the financial costs of the experiment from 2006 through 2010. Three types of experiments were conducted in this study period, including:

(1) Aerial photography steady flow (APSF),
(2) Fall steady flow (FSF), and
(3) High flow experiment (HFE).

The first two types of experimental releases are characterized by steady flows. Aerial photography releases last only a few days. During these periods, water is released from the dam at a constant rate. Typically, these flows are relatively low at 8,000 cubic feet per second (cfs). Release rates during the FSF range from 8,000 to more than 12,000 cfs. The release rate was adjusted so that the same volume of water was released as if no experiment occurred.

The HFE can release a large amount of water. Water releases ramp up in a prescribed pattern and can exceed the Powerplant's maximum flow rate by up to 15,000 cfs for a specified number of hours during the release. During this study period, there was a single HFE that lasted for 4 days and had a maximum flow of almost 42,000 cfs released over a sustained period of 60 hours. This flow rate exceeded the GCD's maximum flow rate so that water went over the spillway without generating electricity.

During normal operations, GCD is governed by stringent operating rules as specified in the ROD. Although these rules may have environmental benefits, they also have financial and economic effects on the value of the energy produced by the GCD Powerplant. These criteria reduce the flexibility of operations, diminish dispatchers' ability to respond to market price signals, and lower the economic and financial benefits of power production. Power benefits are affected by the ROD in two ways. First, the loss of operable capability must eventually be replaced by other power generation resources. Second, the hydropower energy cannot be used to its fullest extent during hours of peak electricity demand when the market price and economic benefits are relatively high.

During experimental releases, operational flexibility is essentially eliminated — water must be released according to a fixed and pre-specified schedule. Relative to the operational restrictions specified under the ROD, an experimental release may have either a positive or negative impact on the financial and economic value of GCD Powerplant energy production. The deviation in the value of power relative to ROD operations that can be directly attributed to an experimental release depends on several complex and interdependent factors. Work performed in this study estimates the financial costs of the experimental releases and identifies the main factors that contribute to these costs and the interdependencies among these factors.

Financial costs are estimated by Generation and Transmission Maximization (GTMax) model simulations of the Salt Lake City Area Integrated Projects (SLCA/IP). This tool uses an integrated systems modeling approach to dispatch power plants in the system while recognizing interactions among supply resources over time. Retrospective simulation for the 1997-through-2005 period made use of extensive sets of data and historical information on SLCA/IP power plants' characteristics and hydrologic conditions and Western Area Power Administration's (Western's) power purchase prices. The GTMax model simulated two scenarios. The "Baseline" scenario assumes that operations comply with ROD operating criteria and experimental releases that actually took place, as documented by Western and Reclamation. The second scenario, "Without Experiments," is identical to the first one, except it assumes that experimental releases did not occur during the study period. Differences in the value of GCD energy production between the two scenarios are used to estimate the change in the value of power attributed to experimental releases. In addition to estimating the financial impact of experimental releases, the

GTMax model was also used to gain insights into the interplay among ROD operating criteria, exceptions that are made to criteria to accommodate the experimental releases, and Western operating practices. Details on the methodology and data sources are explained in Chapter 4 of the report, *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011).

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2 ROD CRITERIA AND WESTERN'S OPERATING PRACTICES

Important factors that explain the financial impacts of experimental releases include the following:

(1) ROD operating criteria,
(2) Exceptions to the ROD made to accommodate the experimental releases,
(3) Monthly and annual water release distribution of annual volumes, and
(4) Western's scheduling guidelines that were adapted in response to ROD restrictions.

This section provides background information on each of these factors.

2.1 ROD Operating Criteria and Exceptions

Reclamation implemented ROD operating criteria to temper water release variability. On October 9, 1996, Bruce Babbitt, then-Secretary of the U.S. Department of the Interior, signed the ROD on operating criteria for the GCD. The criteria selected were based on the Modified Low Fluctuating Flow Alternative as described in the final GCDEIS. These criteria were put into practice by Western beginning in February 1997.

Flow restrictions under the ROD, along with operational limits in effect prior to June 1, 1991, are shown in Table 2.1. The ROD criteria require water release rates to be 8,000 cfs or greater between the hours of 7:00 a.m. and 7:00 p.m., and at least 5,000 cfs at night. The criteria also limit how quickly the release rate can increase and decrease in consecutive hours. The maximum hourly increase (i.e., the up-ramp rate) is 4,000 cfs/hour (hr), and the maximum hourly decrease (i.e., the down-ramp rate) is 1,500 cfs/hr. ROD operating criteria also restrict how much the releases can fluctuate during rolling 24-hour periods. This change constraint varies between 5,000 cfs and 8,000 cfs per day, depending on the monthly volume of water releases. Daily fluctuation is limited to 5,000 cfs in months when less than 600 thousand-acre feet (TAF) are released. The limit increases to 6,000 cfs when monthly release volumes are between 600 TAF and 800 TAF. When the monthly water release volume is 800 TAF or higher, the daily allowable fluctuation is 8,000 cfs.

The maximum flow rate is limited to 25,000 cfs under the ROD operating criteria. Maximum flow rate exceptions are allowed to avoid spills or flood releases during high runoff periods. Under very wet hydrological conditions, defined as when the average monthly release rate is greater than 25,000 cfs, the flow rate may be exceeded, but water must be released at a constant rate.

Table 2.1 Operating Constraints Prior to 1991 and under the ROD (Post 1997)

Operational Constraint	Historic Flows (Pre-1991)	ROD Flows (Post 1997)
Minimum release (cfs)	3,000 summer 1,000 rest of year	8,000 - 7 am - 7 pm 5,000 at night
Maximum release (cfs)	31,500	25,000
Daily fluctuations (cfs/24 hrs)	28,500 summer 30,500 rest of year	5,000; 6,000; or 8,000 depending on release volume [1]
Ramp rate (cfs/hr)	Unrestricted	4,000 up 1,500 down

[1] Limited to 5,000 cfs/day when monthly water release is less than 600 thousand acre-feet (TAF); 6,000 cfs/day when monthly water release is 600 TAF to 800 TAF; and 8,000 cfs/day when monthly water release is greater than 800 TAF.

Source: Reclamation (1996).

Exceptions to the operating criteria in Table 2.1 are made to accommodate experimental releases. For example, maximum flow rates above 25,000 cfs are allowed during an HFE.

Exceptions granted during some experimental releases can potentially increase the financial value of the GCD power resource relative to operations under ROD constraints. Scheduling guidelines adopted by Western's Energy Management and Marketing Office in Montrose, Colorado, can also influence the financial value. An experimental release yields higher financial value when power generation from a prescribed release is concentrated during periods when market prices are relatively high (and power is relatively expensive). This value may exceed the Without Experiments scenario because normal ROD operational criteria do not permit such high generation levels. Also, experimental releases that are only a few days in length and have generation levels that are lower than the minimum value specified in the ROD during times of relatively low market prices (and relatively inexpensive power) may also yield higher financial value than does the Without Experiments scenario. Releasing relatively small amounts of water during low-price hours allows for larger releases during higher-priced hours.

On the other hand, experimental releases that require high water flows during low-price hours typically yield financial values that are lower than those found in the Without Experiments scenario. The situation is exacerbated when an experimental release requires flow rates to exceed turbine capacity because water has to be released through bypass tubes, producing no energy. Spills also increase the tailwater elevation, thereby reducing the effective head and power conversion rates of water passing through the power plant's turbines.

2.2 Monthly Water Release Volumes

Monthly water releases in the Upper and Lower Colorado River Basin are set by Reclamation to be consistent with various operating rules and guidelines, acts, international water treaties, consumption use requirements, State agreements, and the "Law of the River" (Reclamation 2008a). In addition to power production, monthly release volumes are set considering other uses of the reservoirs, such as for flood control, river regulation, consumptive uses, water quality control, recreation, and fish and wildlife enhancement and to address other environmental factors. One requirement is that a minimum of 8.23 million-acre feet (MAF) of water must be released from Glen Canyon Dam each water year (WY) (Reclamation 1970).

Because future hydrologic conditions of the Colorado River Basin cannot be predicted with 100% accuracy, release decisions are made by using current runoff projections provided by the National Weather Service's Colorado Basin River Forecast Center. To be consistent with its annual operating plan, Reclamation adjusts its release decisions on a monthly basis to reflect projections made by rolling 24-month studies that are updated monthly.

For this study, historical SLCA/IP monthly water releases as recorded in Reclamation's Form PO&M-59 (Reclamation undated) were used for the Baseline scenario. These data were provided in a spreadsheet compiled by Western staff (Loftin 2011). In addition, GCD hourly water release data obtained from Reclamation were used for experimental release periods. Under the Without Experiments scenario, monthly water releases during some WYs were assumed to be identical to historical levels. However, in other years it was apparent that monthly water releases would have been different if one or more experimental releases had not occurred during the year. A table with the monthly water releases and the elevations of the Lake Powell reservoir for each scenario during the study period is available in Appendix A at the end of this report.

The redistribution of monthly water releases made to accommodate an experimental release may either raise or lower the financial value of power produced by the GCD Powerplant. Water releases that were shifted to times of the year with higher power market prices, such as during July and August, tend to increase financial value. The opposite occurs when more water is shifted to months when power prices are lower.

2.3 Montrose Scheduling Guidelines

The GCD restrictions shown in Table 2.1 describe operational boundaries; however, within these limitations are innumerable hourly release patterns and dispatch drivers that comply with a given set of operating criteria. The operational range was significantly wider prior to the ROD; however, a wide range of ROD-compliant operational regimes still exists. In addition to operational constraints at the GCD, other SLCA/IP powerplants must also comply with various operational limitations. For example, Flaming Gorge releases are patterned such that downstream flow rates are within Jensen Gauge flow limits. In addition, releases from the Wayne N. Aspinall Dams cannot result in reservoir elevations that are outside of (1) a specified range of forebay elevation levels and (2) limits on changes in reservoir elevations over one- and three-day periods.

Prior to 1990, dispatch from SLCA/IP power plants was primarily driven by market prices. This dispatch philosophy, coupled with a high level of operating flexibility at the SLCA/IPs, allowed Western to produce energy in a pattern that was often distinctly different from its firm loads. As illustrated in Figure 2.1, Western routinely purchased energy during off-peak periods to meet firm loads, storing the water for power generation during on-peak periods when prices were more expensive. By using price as the main driver for SLCA/IP power plant operations, Western was able to maximize the economic value of electricity sales from the GCD Powerplant. Although total daily SLCA/IP energy is short of total load in the example shown in Figure 2.1, the net purchase cost is minimized because purchases are concentrated in hours when prices are relatively low while sales are made when prices are highest.

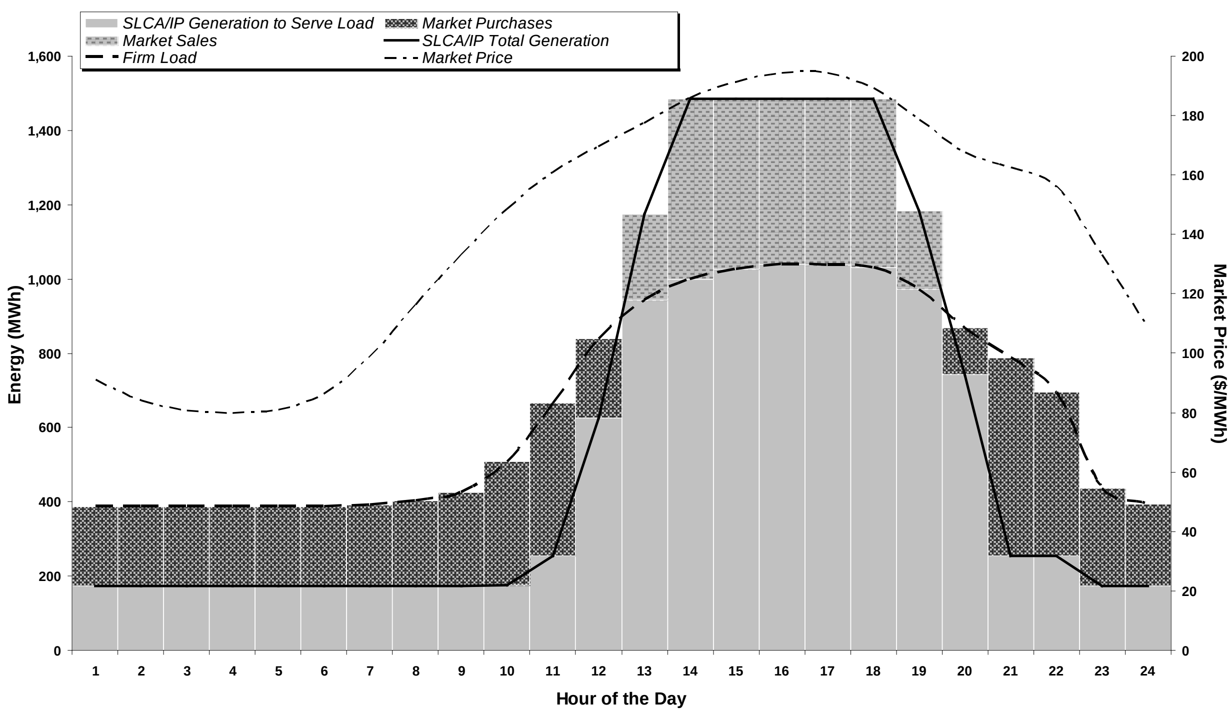

Figure 2.1 Illustration of the Pre-1990 Scheduling Guideline Driven by Market Price, with Flexible Hydropower Operations

As operational constraints were imposed on SLCA/IP resources, including those at the GCD, power plant scheduling guidelines and goals shifted from a model driven primarily by market prices to a new model driven by customer loads. Within the boundaries of these operating constraints, SLCA/IP power resources are used to serve firm load. Western also places a high priority on purchasing power in 16-hour, on-peak blocks and 8-hour, off-peak blocks.

As illustrated in Figure 2.2, SLCA/IP generation resources are typically "stacked" on top of the block purchases as a means of following firm customer load. Because of operational limitations, Western staff may need either to purchase or sell varying amounts of energy on an hourly basis. The volumes of these variable market purchases are relatively small under the vast majority of conditions.

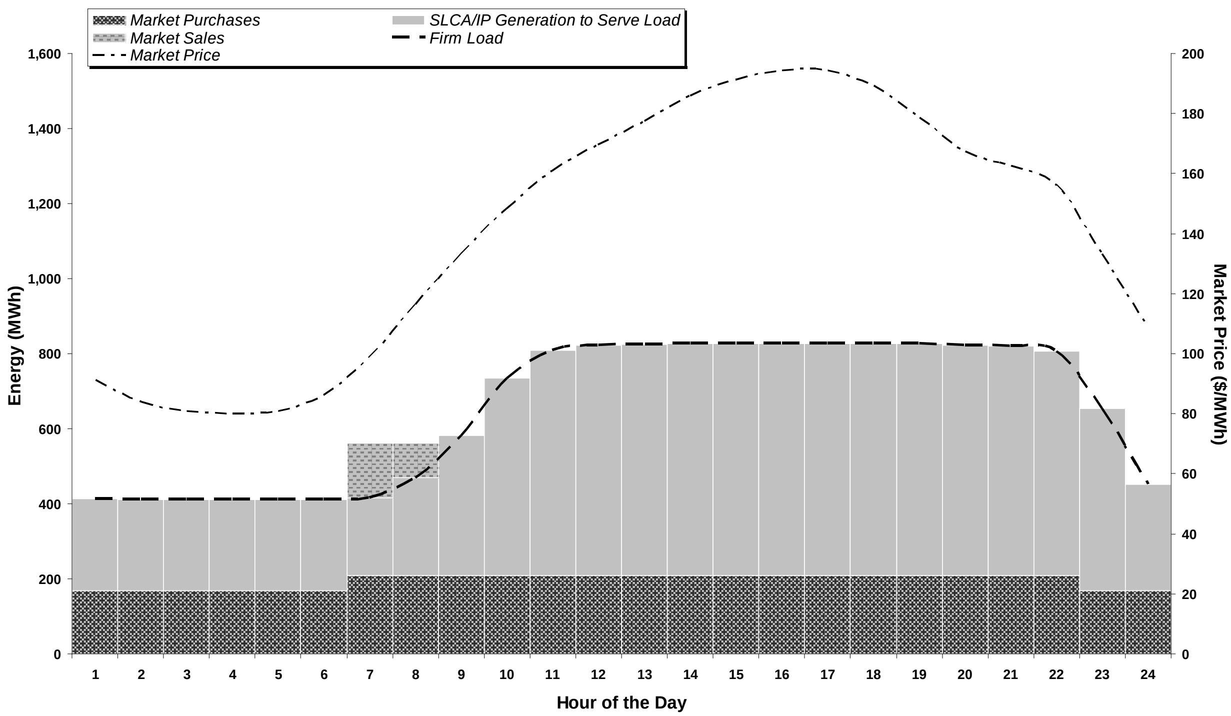

Figure 2.2 Illustration of the Firm-Load-Driven Dispatch Guideline under the 1996 ROD Operating Criteria when SLCA/IP Resources Are Short of Load

Market sales can be significant when SLCA/IP resources exceed firm load. Under load-following guidelines, excess hydropower generation is sold during hours with the highest price while complying with operational limits. On-peak sales are limited by maximum SLCA/IP generation levels that are constrained by limits on hourly ramp rates and daily change constraints. However, significant excess power generation rarely occurs, because projected power production in excess of sustainable hydropower (SHP) is sold to SLCA/IP customers on a short-term basis as available hydropower (AHP). SHP, which is based on an established risk level, is a fixed level of long-term capacity and energy available from SLCA/IP facilities during summer and winter seasons; this amount is the minimum commitment level for capacity that Western will provide to all SLCA/IP customers. AHP is the monthly capacity and energy that is actually available based on prevailing water release conditions; thus, it is the amount that Western offers to its customers above and beyond their SHP levels. These terms are explained in greater detail in Section 4.1 of Veselka et al. (2011).

The load-following scheduling objective facilitates a strong link between Western's contractual obligations and SLCA/IP operations, requiring dispatch among SLCA/IP power plants to be closely coordinated. This interdependency exists because loads and hydropower resources are balanced whenever feasible. Western is therefore able to indirectly affect SCLA/IP power plant operations and hourly reservoir releases via specifications in its contract amendments. Contract terms that indirectly affect power plant operations include SHP and AHP capacity and energy sales, as well as Minimum Schedule Requirement (MSR) specifications. The MSR is the minimum amount of energy that a customer must schedule from Western in each hour. The load-following dispatch philosophy minimizes scheduling problems and helps Western avoid non-compliant water releases.

In contrast, the market price dispatch objective only weakly links firm power sales contracts to SLCA/IP operations, if at all. Except for coordinating releases from the Aspinall and Molina units, the market price objective allows for independent dispatch among power plant operations, whereby each plant is dispatched to maximize net revenues. Hourly differences between loads and resource production are reconciled though market purchases and sales.

In addition to load following, dispatchers follow other practices that are specific to GCD Powerplant operations. These practices fall within ROD operational boundaries but are not ROD requirements. Therefore, these institutional practices may be altered or abandoned by Western at any time. One practice involves reducing generation at Glen Canyon to the same minimum level every day during low-price, off-peak hours. Western also avoids drastic changes to total water volume releases when they occur over successive days. In this analysis, it was assumed that the same volume of water was released each weekday.

Another Western scheduling practice that was observed when examining water releases occurring on both Saturdays and Sundays is that weekend releases are generally not less than 85% of the average weekday release (Patno 2008). In addition, during the summer season, one cycle of raising and lowering GCD Powerplant output is recommended. This practice increases to a maximum of two cycles during other seasons of the year as dictated by the hourly load pattern.

Changes in Western's scheduling guidelines did not occur abruptly but subtly and over a period of months. These changes were not only the result of the operational constraints imposed by the ROD but also attributable to changing market conditions, such as persistent drought, electricity market disruptions in 2000 and 2001, and extended experimental releases that had large daily flow rate fluctuations. Western felt that by instituting load-following dispatch, they could better control their exposure and risk to market price fluctuations (Palmer 2010). By the beginning of this study period, Western had fully implemented the new scheduling guidelines.

Scheduling guidelines are practiced not only at Glen Canyon but also at other SLCA/IP power plants. For example, the Collbran Project's daily generation produced by the Upper and Lower Molina power plants is scheduled at or near power plant maximum capability for continuous blocks of time, the lengths of which are based on the amount of water that is available for release during a 24-hour period. Western also has scheduling guidelines for daily water releases from Blue Mesa Reservoir. Water is released from Blue Mesa seven days a week to accommodate higher runoffs, except from November through February, when water is not released on Saturdays. The decision not to release water on Saturdays was made for economic reasons so that more water could be released during higher-priced hours during the week.

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3 DESCRIPTION OF EXPERIMENTAL RELEASES

Three types of experimental releases were conducted during the study period: (1) aerial photography steady flow; (2) fall steady flow; and (3) high flow experiment. This section describes each type of experimental release, its characteristics, and when each occurred. Table 3.1 summarizes the operational characteristics of the GCD Powerplant during the experimental releases, such as maximum and minimum flows, maximum daily fluctuation, and maximum and minimum ramp rates. The term water year (WY) will be used from this point forward in the report. It is defined as a 12-month period from October 1 to September 30. For example, WY 2008 runs from October 1, 2007 to September 30, 2008. No experiments were conducted in WYs 2006 and 2007.

3.1 Aerial Photography Steady Flow (APSF)

This release pattern provides a constant water release ranging from 3 to 5 days. It is performed so that aerial photographs can be taken over the river to monitor the status of natural and cultural resources along the river and to see how these resources change in response to dam operations. These flows are performed during weekends and holiday periods to minimize impacts to power customers. The flow pattern for the APSF in May 2009 is displayed graphically in Figure 3.1; the flow rate was relatively low at 8,000 cfs. Normal dam operations resumed about 8:00 a.m. on May 31. Because APSFs are of short duration, water is only reallocated within the month the release occurs.

Table 3.1 Characteristics of GCD Powerplant Experimental Release Events, By Dates of Releases

Event[1]	Date	Maximum Flow (cfs)	Minimum Flow (cfs)	Hourly Up-Ramp Rate (cfs/hr)	Hourly Down-Ramp Rate (cfs/hr)	Maximum Daily Fluctuation (cfs/day)	Water Reallocated within Year	Exception to ROD Criteria
HFE	3/5/2008–3/9/2008	41,185	8,046	1,925	1,646	32,687[2]	Yes	Exceeded maximum release rate of 25,000 cfs
FSF	9/1/2008–10/31/2008	12,738	11,263	872	870	974	No	No
APSF	5/22/2009–5/31/2009	8,018	7,801	1,413	1,477	4,229[1]	No	No
FSF	9/1/2009–10/31/2009	11,076	8,154	1,774	976	2,011	No	No
FSF	9/1/2010–10/31/2010	8,805	7,428	791	742	1,029	No	No

[1] No experiments were conducted in WYs 2006 and 2007.
[2] This fluctuation would only occur when Glen Canyon Dam was either ramping up or ramping down to or from the steady flow.

3.2 Fall Steady Flow (FSF)

The purpose of steady flows in the fall months of September and October are to create warmer water conditions to help young humpback chubs survive prior to the onset of winter. The FSF is also expected to create and improve backwater rearing habitats of the humpback chub by increasing their spatial extent, promoting habitat stability, and improving habitat temperature and availability of prey (Reclamation 2007). These flows began in September 2008 and will continue for five years through 2012 (Reclamation 2008b).

The water release rate is determined such that the water volume released in a month is the same as what would have occurred in the absence of the experiment. A typical FSF flow pattern is shown in Figure 3.2. The September/October 2008 FSF had a nominal constant flow of about 12,000 cfs, with a maximum flow reaching above 12,700 cfs and a minimum flow of about 11,300 cfs. The September/October 2009 FSF had a nominal constant flow of 10,000 cfs, with a maximum flow of almost 11,100 cfs and a minimum flow of about 8,150 cfs. Finally, the September/October 2010 FSF had a nominal constant flow of about 8,000 cfs, with a maximum flow of about 8,800 cfs and a minimum flow of about 7,400 cfs.

However, some fisheries' biologists recommend that Reclamation conduct steady flows during the summer months when the young chub first enter the main stem of the Colorado River from the tributary habitat where they hatch (Land Letter 2010).

It is of note that the FSF occurs over two water years. Therefore, only the September 2010 portion of the FSF that occurred in the fall of 2010 will be reported in WY 2010. The October 2010 portion will be part of the cost analysis for WY 2011, which will occur at a later date.

3.3 High Flow Experiment (HFE)

A high flow experiment, which occurred over a 5-day period in November 2004, is similar to a Beach/Habitat-Building flow. The purpose of HFEs is to rebuild sandbars and beaches; improve the riparian resources and protect archaeological resources by building up sandbars and re-depositing sand at higher elevations; preserve and restore camping beaches; reduce near-shore vegetation; and rejuvenate backwaters, which can be important rearing habitat for native fish. The HFE that occurred in March 2008 was designed to mobilize sediment available from floods of the Paria and Little Colorado Rivers and redistribute it within the Colorado River (NPCA 2010).

The March 2008 high flow experiment ran from March 2 to 9. The peak maximum flow of the HFE reached over 41,180 cfs and was sustained for 60 hours. This flow rate exceeded the capability of the turbines at that time, so water released through the bypass tubes reached 15,000 cfs. No electricity was generated by the water released through the bypass tubes. So that sufficient water was available to perform this event, water that would otherwise have been used in months after this event was redistributed for use during the HFE. The flow pattern for this HFE is shown graphically in Figure 3.3.

On March 2, releases were increased at a rate of approximately 1,500 cfs/hour until the Powerplant's capacity was reached. Once capacity was reached, each of the four bypass tubes was opened. Then, bypass releases were increased every three hours by about 1,900 cfs until all bypass tubes are operating at full capacity for a total bypass release of about 15,000 cfs. A constant flow was maintained for 60 hours with flow changes of less than 1,000 cfs/day. After 60 hours, the discharge was lowered at a down-ramping rate of about 1,500 cfs/hour until normal Powerplant releases scheduled for March were reached.

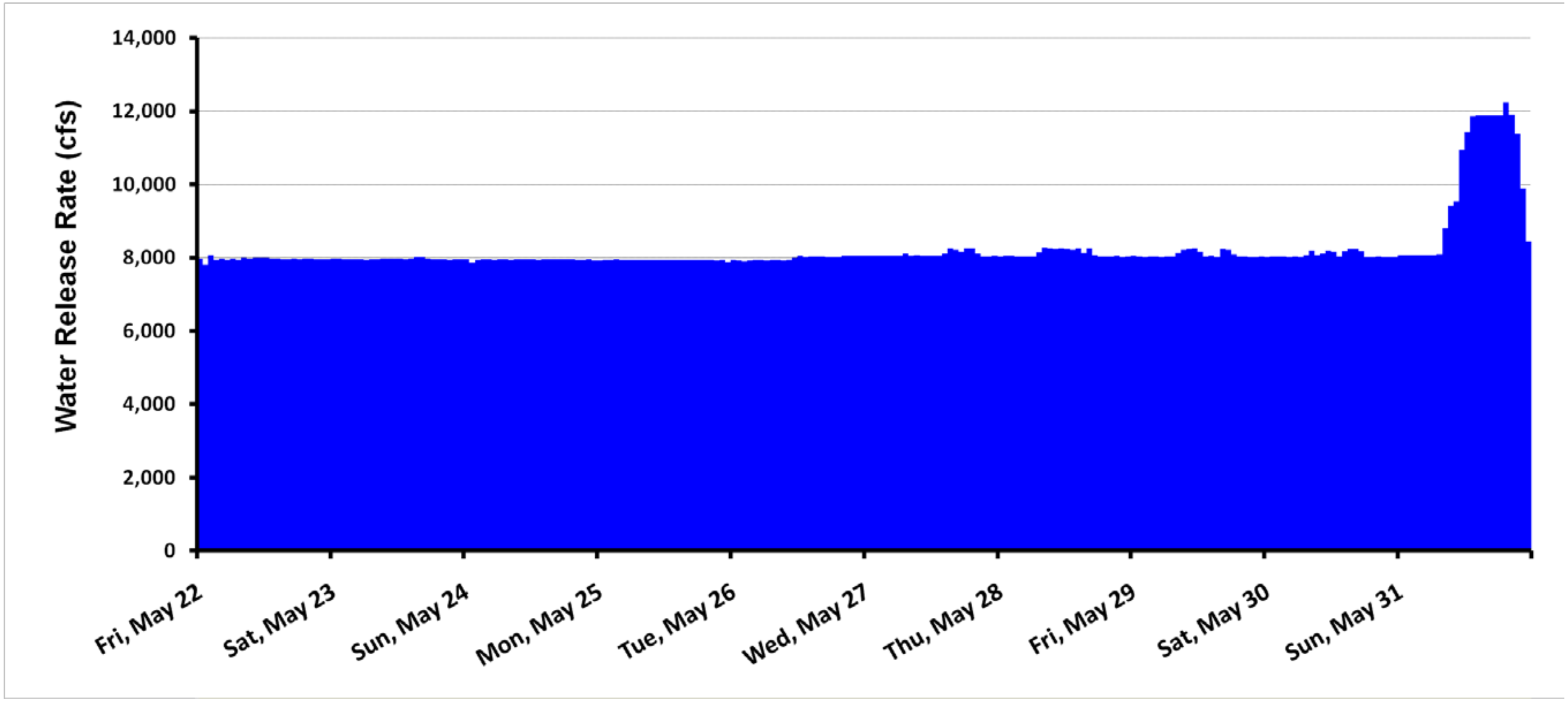

Figure 3.1 Release Pattern for the Aerial Photography Steady Flow Conducted in May 2009

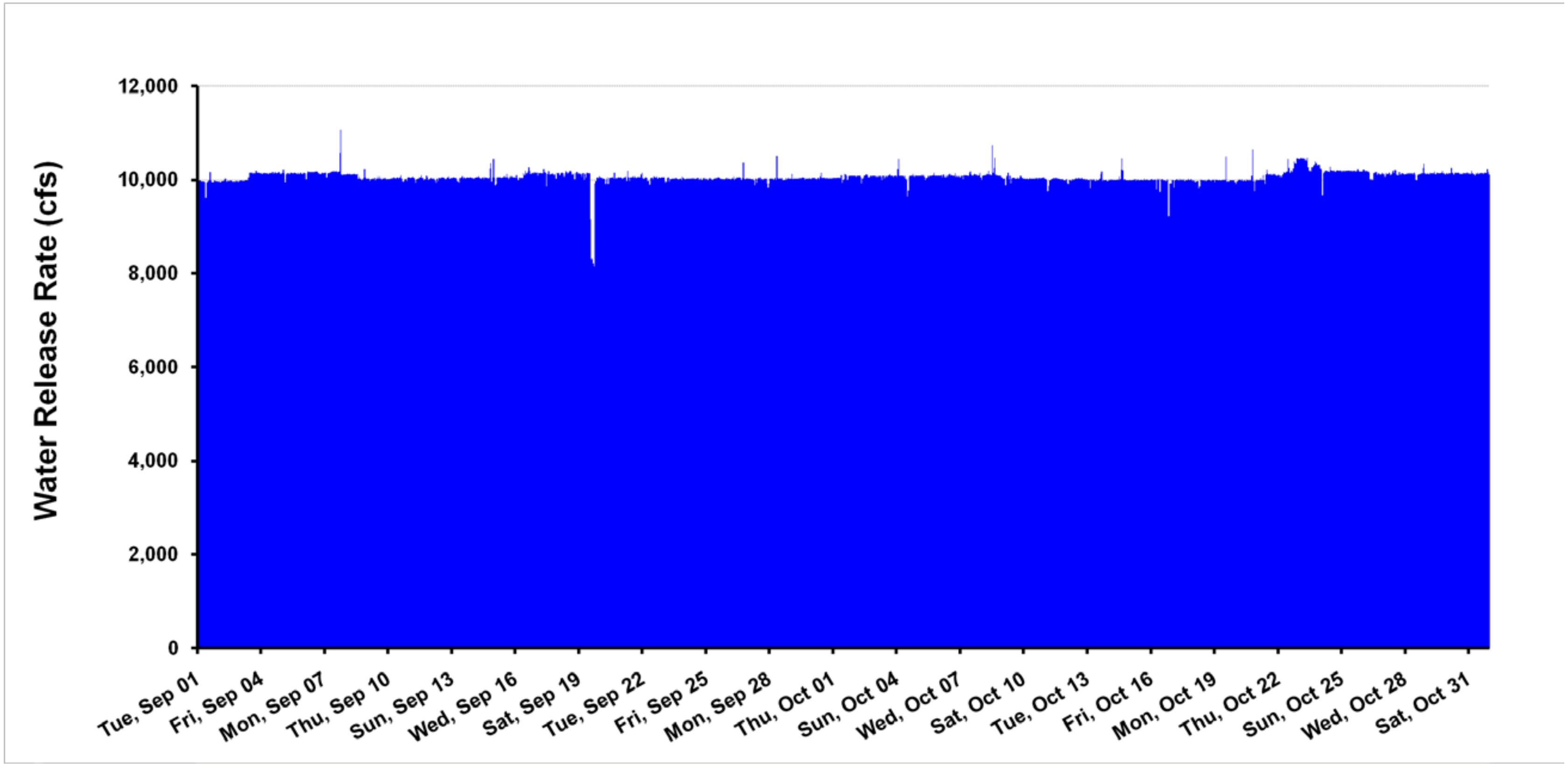

Figure 3.2 Release Pattern of the Fall Steady Flow Conducted in September/October 2009

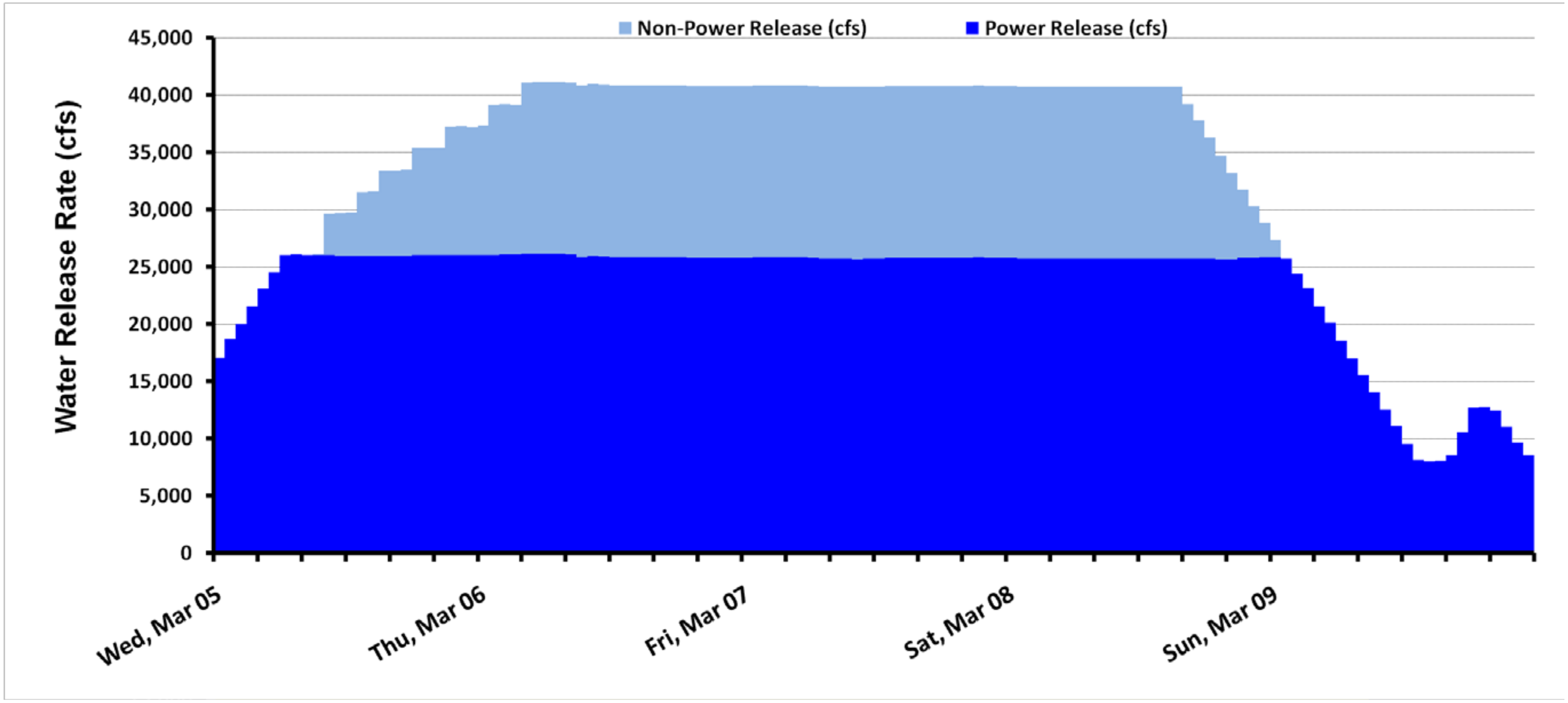

Figure 3.3 Release Pattern of the High Flow Experiment Conducted in March 2008

4 METHODS AND MODELS

Financial impacts are computed as the difference in the values of GCD energy production between two simulated operating scenarios, as follows:

(1) The **Baseline scenario,** which assumes ROD operating criteria, the occurrence of exceptions to the ROD criteria that could accommodate a series of experimental releases, and historical monthly release volumes; and
(2) The **Without Experiments scenario,** which assumes ROD operating criteria without exceptions, that no experimental releases took place, and monthly release volumes that may differ from historical levels in some years.

The GTMax model is the main simulation tool used to dispatch SCLA/IP hydropower plants, including Glen Canyon. It not only simulates Glen Canyon operations, but it also provides insights into the interplay among ROD operating criteria, exceptions to the criteria to accommodate experimental releases, modifications to monthly water volumes, and Western scheduling guidelines and goals. The GTMax model is supported by several other tools and databases as described in the following sections. These support tools include: SLCA/IP Contracts spreadsheet, Customer Scheduling algorithm, Market Price spreadsheet, Experimental Release spreadsheet, and a Financial Value Calculation spreadsheet.

The GTMax model is supported by an input spreadsheet that contains ROD operating criteria, historical hydropower operations data, and parameters for Western scheduling guidelines. The input spreadsheet also performs various computations and prepares input data for the model. GTMax results are transferred to another spreadsheet to summarize simulation results, perform cost calculations, extrapolate weekly results to a monthly total, and produce a variety of tables and graphs.

The methods, models, and data used in this analysis were discussed in detail in Section 4 of the earlier report, *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011).

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5 RESULTS

This section discusses results of simulation runs during the study period of 2006 to 2010. The results are displayed by WYs, which run from October 1 to September 30, and the costs are in nominal dollars.

There are two broad categories of experiments that occurred during this period. Experiments in the first category (Category 1) are relatively short in duration and require changes in hourly release volumes from the normal pattern. Changes in releases during the experiment may require an increase or decrease in releases during non-experimental periods in the month in which they occur as compared to the Without Experiments scenario. The monthly water volumes are identical under both scenarios.

Experiments in the second category (Category 2) can be either short or long in duration but have different monthly water release volumes from those of the Without Experiments scenario. This second category of experiment also exhibits an hourly release pattern that differs from the pattern during non-experiment periods.

The financial impacts of the experimental releases that occurred in each year are discussed in detail below. Because no experiments occurred in either WYs 2006 or 2007, the discussion of financial costs begins in WY 2008.

Table 3.1 provides characteristics of the experimental releases, including the dates on which they occurred, minimum and maximum flows, hourly up- and down-ramp rates, and maximum daily fluctuations, as well as whether monthly water reallocations were required and whether ROD operating criteria were relaxed during the experiment.

The spread between the on- and off-peak prices that Western paid for power is a key factor in estimating the financial impacts of experiments conducted at GCD. Except for HFE spills and the resulting lowering of the Lake Powell reservoir forebay elevation, most experiments have relatively little effect on the amount of electricity generated by the GCD Powerplant over the course of a year. Experiments that incur a financial loss shift water releases and power generation from times when electricity prices are high to times when prices are low. The greater the difference between on-peak and off-peak prices, the higher is the financial loss. The absolute price is of little or no importance. For example, if the price of electricity is constant at $1,000 per megawatt-hour (MWh) during a month, an experiment that does not reallocate monthly water volumes would incur little or no cost. The experiment merely affects the hourly timing of releases and not the total monthly value.

The price spread between hours in a month is important for the first category of experiments because a reallocation of hourly water releases within a month is required. When an experiment requires shifting water among months of the year, not only is the price spread within the hours of the month important, but price spreads among the months of the year are also important. Experiments that shift higher release volumes out of months of the year that have higher prices, such as July and August, and into months of the year with lower prices, such as April and May, incur relatively high financial costs.

5.1 Cost of Experiments in WY 2008

Two experimental releases were conducted in this year, namely, a Category 2 HFE and a Category 1 APSF. The HFE lasted from March 5 to March 9 and sustained a flow rate of almost 41,200 cfs for 60 hours. Because the peak flow rate exceeded the capabilities of the turbines, the water released through the bypass tubes reached 15,000 cfs. The second release was an FSF, which began in September and continued through October, thus carrying the release into WY 2009. The FSF was a steady flow that had a nominal release rate of 12,000 cfs.

The pattern of the HFE required more water to be released in March than is normal. Therefore, water was reallocated among the remaining months of WY 2008. Figure 5.1 shows the monthly water releases for both scenarios. Monthly water releases under the Without Experiments scenario were estimated by Argonne staff on the basis of the actual release pattern and the tendency to release higher water volumes during the summer months to take advantage of higher market prices during these periods. In addition, the amount of water released in the water year under both scenarios was identical. Therefore, more water was released in nearly every month following the HFE through the end of the water year.

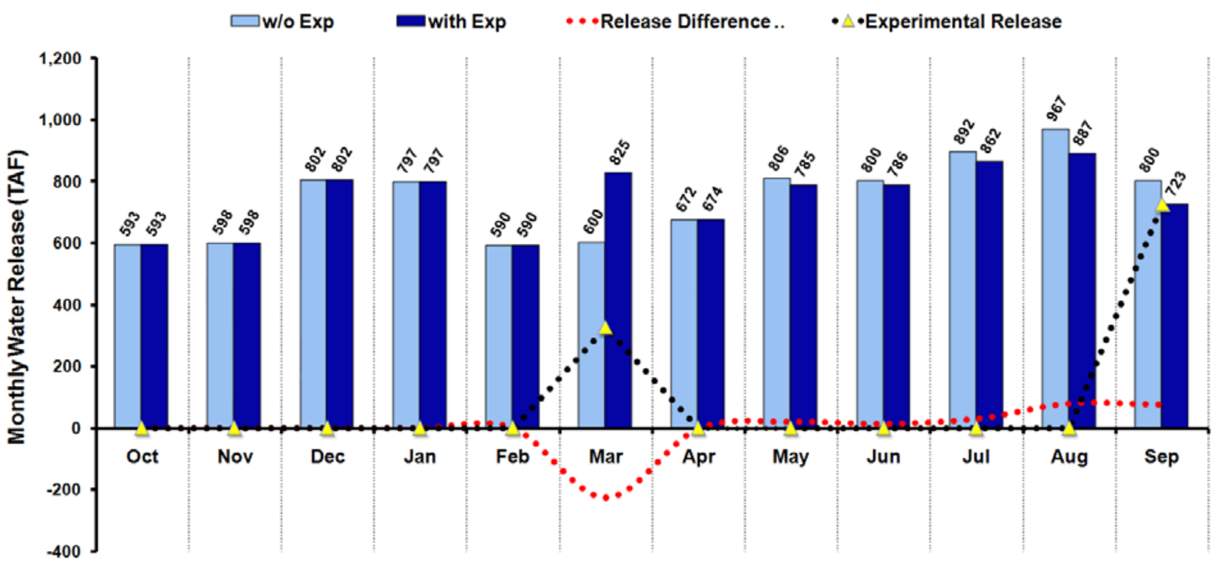

Figure 5.1 Monthly Water Releases in WY 2008 (Note: “with Exp” = the Baseline scenario)

Figure 5.2 shows the monthly costs and benefits resulting from these two experimental releases. Because there were two experiments performed in this year and one of them, the HFE, required a redistribution of water release volumes among months within the year, the financial impacts of each experimental release cannot be determined individually.

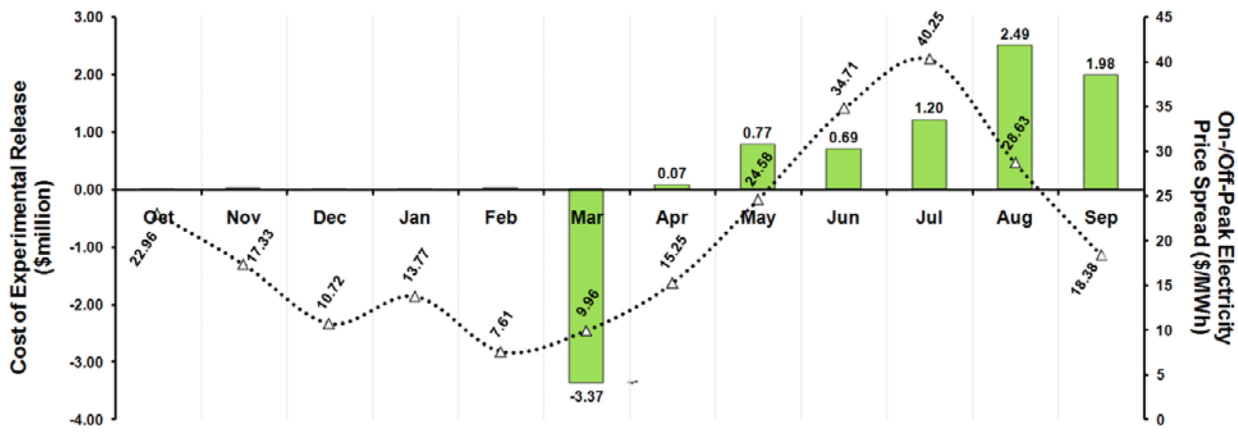

Figure 5.2 Cost of Experimental Releases in WY 2008

The HFE in March resulted in a benefit of almost $3.4 million because about 225 TAF more water was released in that month than would have been released without the experiment. The secondary y-axis on this chart shows the difference, or spread, in the average monthly on-peak and off-peak prices that Western pays to purchase power. The cost benefit might have been larger except for the fact that water was spilled because the flow exceeded the turbine capability for almost 90 hours (60 hours of steady maximum flow plus time to ramp up to and down from the maximum). Approximately 93 TAF of water was released through bypass tubes and therefore did not generate electricity. The months following the HFE had costs because less water was released in those months to make up for the excess water released in March.

The costs in April through September ranged from a high of about $2.5 million in August to a low of $70,000 in April. August had the highest cost because the Baseline scenario released significantly less water — namely, 80 TAF — than did the Without Experiments scenario. April had the lowest cost despite the fact that the Baseline scenario released slightly more water (2 TAF) than occurred under the Without Experiments scenario (Figure 5.1). This cost is attributable to the difference in the Lake Powell elevation between the two scenarios. Because the HFE in the Baseline scenario released more water than the Without Experiments scenario, the reservoir in the Baseline scenario had a slightly lower elevation, which consequently reduced the power conversion factor. Therefore, less energy is produced in the Baseline scenario for each unit of water passing through the turbines than is produced in the Without Experiments scenario.

During the months of May and June under the Without Experiments scenario, the ROD daily change requirement is 8,000 cfs because each month's release exceeds 800 TAF. Under the Baseline scenario the daily change requirement is 6,000 cfs because each month's release is between 600 to 800 TAF (see Table 2.1). A higher daily change limit under the Without Experiment scenario allows Western to take advantage of the available capacity at Glen Canyon thereby producing more energy during higher priced peak hours.

The cost in September arises because of two factors: (1) more water was released in the Without Experiments scenario than under the Baseline scenario because of the HFE in March, and (2) September was the first month of the FSF. Because the FSF required water to be released at a constant flow of about 12,000 cfs, the same amount of water was released in off-peak and on-peak hours. Therefore, Western was unable to take advantage of the price spread between on- and off-peak hours by allocating more water in the peak daytime hours. The cost of the experiment in September might have been higher if the price spread had been larger. Although the difference in water released between the two scenarios was about the same in August and September, the cost was about 20% lower in September than August. This result likely occurred because the price spread dropped by more than 35%.

Over this entire water year, there was a combined net cost of more than $3.8 million for these two experiments.

5.2 Cost of Experiments in WY 2009

Two types of experimental releases occurred in this water year: namely, the second month of the fall 2008 FSF in October, the first month of the fall 2009 FSF in September, and an APSF in May. The fall 2008 FSF had a nominal steady flow of 12,000 cfs, and the fall 2009 FSF had a nominal steady flow of 10,000 cfs. The APSF occurred from May 22 to May 31 and had a steady flow of 8,000 cfs. Water was only reallocated within the month the experiment occurred; therefore, both scenarios had the same amount of water released in all months.

Figure 5.3 shows that relatively small costs occurred in all months with experiments. The second month of the fall 2008 FSF had a cost of $390,000, the APSF had a cost of almost $20,000, and the first month of the fall 2009 FSF had a cost of almost $70,000. The total annual cost was almost $480,000.

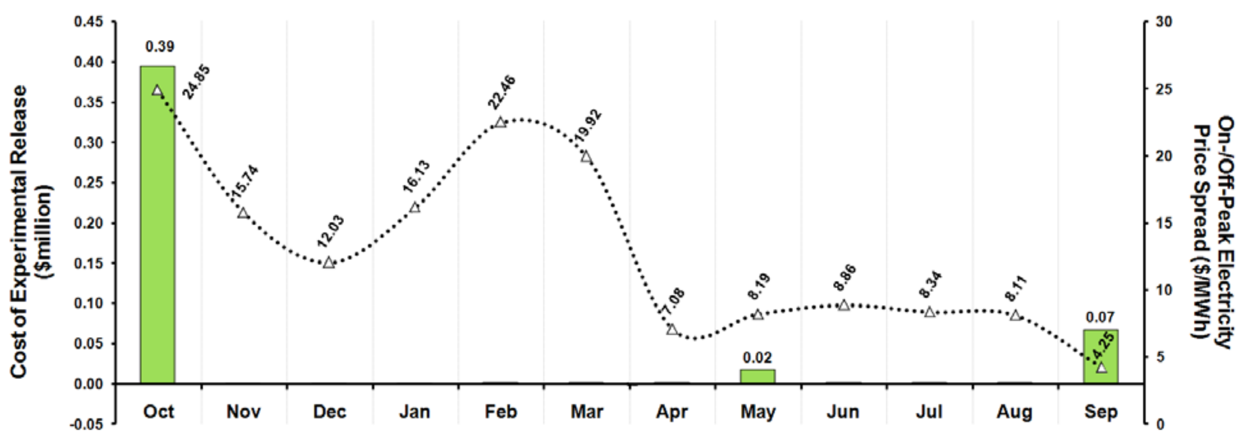

Figure 5.3 Cost of Experimental Releases in WY 2009

All of these experiments required water to be released at a steady rate over a certain period of time: the FSFs over an entire month and the APSF over a span of 9 days. As noted in WY 2009, the same amount of water was released in off-peak and on-peak hours. Therefore, Western was unable to take advantage of the price spread between on- and off-peak hours, resulting in a cost for performing the experiment. The cost was highest in October because the experiment lasted the entire month and because of the large spread in the on- and off-peak price. The cost of the FSF in September was substantially lower than in October because the price spread was substantially smaller in that month (4.25 $/MWh) relative to the price spread in October (almost $25/MWh). Finally, the cost of the APSF was smaller still because this release lasted only 9 days and the price spread in May was low.

5.3 Cost of Experiments in WY 2010

This year had only a single type of Category 1 experiment: namely, the second month of an FSF in October and the first month of an FSF in September. The FSF in fall 2009 had a nominal steady flow of 10,000 cfs, and the FSF in fall 2010 had a nominal steady flow of 8,000 cfs. Water was only reallocated within the month the experiment occurred; therefore, both scenarios had the same amount of water released in all months.

Figure 5.4 shows the costs associated with both of the FSFs. The cost of the FSF in October was about $200,000, and the cost in September was $310,000, for a total annual cost of $510,000. As noted with FSFs in other WYs, these experiments result in a cost because with steady flows the entire month, Western is unable to allocate water throughout the day to take advantage of the price spread between on- and off-peak hours.

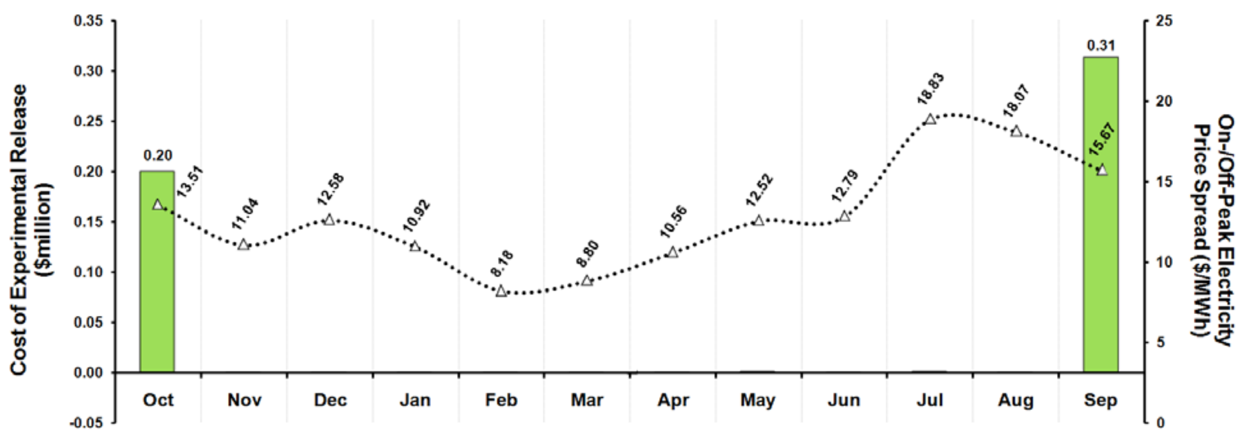

Figure 5.4 Cost of Experimental Releases in WY 2010

It is useful to compare the FSF cost in October of this water year to the FSF cost in September of the previous water year because they are part of the same experiment and have the same steady flow rate. The FSF cost in October is about 3 times higher than the FSF of the previous month because the price spread is 3 times higher in October (see Figure 5.4) than in September (see Figure 5.3).

5.4 Summary

Table 5.1 summarizes the results of the experiments conducted during the study period. Each experiment is listed in the water year(s) in which it occurred, along with the cost of the experiment and the total water released during the experiment. No experiments were conducted in WYs 2006 and 2007. For the HFE that occurred in WY 2008 and the FSF in fall 2008, the costs are combined. The cost of each experiment could not be determined individually because water reallocated for the HFE affected the amount of water released for the Without Experiment scenario in September 2008. Finally, only the first month of the FSF in fall 2010 was calculated because some data for October 2010 were not yet available. The total cost of this experiment will be determined in a subsequent report.

Table 5.1 Summary of Experimental Flow Characteristics by Water Year

Water Year[1]	Experiment (s)	Cost of Experiment(s) ($ millions)	Total Experimental Releases (TAF)
2008/2009	HFE, FSF[2]	4.22	1,797
2009	APSF	0.02	163
2009/2010	FSF	0.27	1,218
2010	FSF (September only)	0.31	480
TOTAL DURING STUDY PERIOD		**$4.82**	**3,658**

[1] No experiments were conducted in WYs 2006 and 2007.
[2] Cost of experiments could not be determined individually because water was reallocated over the 6 months following the HFE.

All of the experiments during this study period resulted in a cost (i.e., a loss of potential income). The total cost of all experiments during the study period was in excess of $4.8 million.

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APPENDIX A:

GLEN CANYON DAM MONTHLY WATER RELEASES AND RESERVOIR ELEVATIONS BY SCENARIO DURING THE STUDY PERIOD

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GLEN CANYON DAM MONTHLY WATER RELEASES AND RESERVOIR ELEVATIONS BY SCENARIO DURING THE STUDY PERIOD

Table A.1 shows the monthly water releases and elevation of Lake Powell by scenario during the study period.

Table A.1 Water Releases and Lake Powell Elevation by Scenario and WY

Water Year	Month	Baseline		Without Experiments	
		Water Release (TAF)	Lake Powell Elevation (feet [ft])	Water Release (TAF)	Lake Powell Elevation (ft)
2006	Oct	496.1	3,602.8	496.1	3,602.8
2006	Nov	501.8	3,602.4	501.8	3,602.4
2006	Dec	803.7	3,598.2	803.7	3,598.2
2006	Jan	801.1	3,594.3	801.1	3,594.3
2006	Feb	803.3	3,589.8	803.3	3,589.8
2006	Mar	600.7	3,588.7	600.7	3,588.7
2006	Apr	601.9	3,592.9	601.9	3,592.9
2006	May	597.6	3,605.0	597.6	3,605.0
2006	Jun	801.4	3,610.4	801.4	3,610.4
2006	Jul	826.8	3,606.9	826.8	3,606.9
2006	Aug	828.0	3,602.8	828.0	3,602.8
2006	Sep	532.0	3,601.8	532.0	3,601.8
2007	Oct	601.5	3,608.0	601.5	3,608.0
2007	Nov	598.5	3,606.8	598.5	3,606.8
2007	Dec	801.4	3,606.4	801.4	3,606.4
2007	Jan	802.1	3,599.5	802.1	3,599.5
2007	Feb	604.6	3,597.9	604.6	3,597.9
2007	Mar	598.3	3,598.8	598.3	3,598.8
2007	Apr	595.1	3,600.3	595.1	3,600.3
2007	May	595.7	3,608.6	595.7	3,608.6
2007	Jun	799.2	3,611.6	799.2	3,611.6
2007	Jul	799.8	3,607.4	799.8	3,607.4
2007	Aug	799.8	3,603.8	799.8	3,603.8
2007	Sep	598.0	3,601.9	598.0	3,601.9

Table A.1 (Cont.)

Water Year	Month	Baseline		Without Experiments	
		Water Release (TAF)	Lake Powell Elevation (ft)	Water Release (TAF)	Lake Powell Elevation (ft)
2008	Oct	593.4	3,600.7	593.4	3,600.7
2008	Nov	597.6	3,598.6	597.6	3,598.6
2008	Dec	801.8	3,594.7	801.8	3,594.7
2008	Jan	796.9	3,590.7	796.9	3,590.7
2008	Feb	589.9	3,590.6	589.9	3,590.6
2008	Mar	824.6	3,589.6	600.0	3,592.2
2008	Apr	673.8	3,593.9	672.2	3,596.4
2008	May	785.4	3,610.5	806.0	3,612.5
2008	Jun	786.0	3,630.9	800.0	3,632.6
2008	Jul	861.8	3,633.1	891.8	3,634.5
2008	Aug	886.8	3,629.5	966.8	3,630.2
2008	Sep	723.3	3,627.0	800.0	3,627.0
2009	Oct	748.6	3,623.9	748.6	3,623.9
2009	Nov	595.9	3,621.9	595.9	3,621.9
2009	Dec	796.9	3,617.9	796.9	3,617.9
2009	Jan	798.0	3,614.2	798.0	3,614.2
2009	Feb	597.5	3,612.1	597.5	3,612.1
2009	Mar	619.8	3,610.5	619.8	3,610.5
2009	Apr	597.6	3,611.2	597.6	3,611.2
2009	May	574.9	3,629.0	574.9	3,629.0
2009	Jun	655.8	3,640.4	655.8	3,640.4
2009	Jul	799.4	3,641.2	799.4	3,641.2
2009	Aug	796.6	3,637.6	796.6	3,637.6
2009	Sep	598.0	3,635.4	598.0	3,635.4
2010	Oct	619.9	3,634.1	619.9	3,634.1
2010	Nov	681.5	3,631.1	681.5	3,631.1
2010	Dec	897.7	3,626.2	897.7	3,626.2
2010	Jan	896.3	3,622.2	896.3	3,622.2
2010	Feb	628.9	3,620.2	628.9	3,620.2
2010	Mar	601.0	3,619.4	601.0	3,619.4
2010	Apr	598.2	3,620.5	598.2	3,620.5
2010	May	596.1	3,625.7	596.1	3,625.7
2010	Jun	596.4	3,638.8	596.4	3,638.8

Table A.1 (Cont.)

Water Year	Month	Baseline		Without Experiments	
		Water Release (TAF)	Lake Powell Elevation (ft)	Water Release (TAF)	Lake Powell Elevation (ft)
2010	Jul	798.9	3,636.6	798.9	3,636.6
2010	Aug	800.5	3,634.6	800.5	3,634.6
2010	Sep	480.2	3,633.7	480.2	3,633.7

APPENDIX B:

MONTHLY ON- AND OFF-PEAK ELECTRICITY PRICES

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MONTHLY ON- AND OFF-PEAK ELECTRICITY PRICES

Table B.1 shows weighted average monthly on- and off-peak electricity prices that Western paid to purchase AHP energy during the study period. Prices are based on total purchases in terms of dollars and kilowatt hours.

Table B.1 Weighted Average Monthly On- and Off-Peak Electricity Prices by Calendar Year

Year	Month	Off-Peak ($/MWh)	On-Peak ($/MWh)	Experiments Conducted
2005	Jan	42.89	63.45	
2005	Feb	43.67	71.09	
2005	Mar	45.96	48.61	
2005	Apr	38.84	60.99	
2005	May	38.74	52.86	
2005	Jun	29.07	51.44	
2005	Jul	33.85	69.80	
2005	Aug	52.04	61.68	
2005	Sep	60.72	69.21	
2005	Oct	53.53	69.72	
2005	Nov	56.63	68.00	
2005	Dec	56.32	79.88	
2006	Jan	49.65	69.94	
2006	Feb	54.15	84.25	
2006	Mar	42.43	67.40	
2006	Apr	35.38	46.66	
2006	May	33.86	52.43	
2006	Jun	37.79	55.90	
2006	Jul	48.37	75.14	
2006	Aug	38.27	62.39	
2006	Sep	30.88	41.38	
2006	Oct	34.98	51.10	
2006	Nov	44.44	56.71	
2006	Dec	44.30	62.10	
2007	Jan	45.52	56.95	
2007	Feb	47.35	58.38	
2007	Mar	44.62	53.38	
2007	Apr	41.96	56.63	
2007	May	43.15	61.82	
2007	Jun	39.75	63.13	
2007	Jul	46.34	64.08	
2007	Aug	43.61	64.57	

Table B.1 (Cont.)

Year	Month	Off-Peak ($/MWh)	On-Peak ($/MWh)	Experiments Conducted
2007	Sep	33.31	48.27	
2007	Oct	36.54	59.50	
2007	Nov	40.93	58.26	
2007	Dec	52.55	63.27	
2008	Jan	53.26	67.03	
2008	Feb	56.90	64.51	
2008	Mar	61.04	71.00	HFE
2008	Apr	67.29	82.54	HFE[1]
2008	May	52.98	77.56	HFE[1]
2008	Jun	50.18	84.89	HFE[1]
2008	Jul	54.96	95.21	HFE[1]
2008	Aug	48.52	77.15	HFE[1]
2008	Sep	34.45	52.83	HFE[1], FSF
2008	Oct	32.62	57.47	FSF
2008	Nov	35.92	51.66	
2008	Dec	40.05	52.08	
2009	Jan	35.02	51.15	
2009	Feb	29.96	52.42	
2009	Mar	25.62	45.54	
2009	Apr	23.06	30.14	
2009	May	22.40	30.59	APSF
2009	Jun	24.42	33.28	
2009	Jul	30.65	38.99	
2009	Aug	31.15	39.26	
2009	Sep	30.90	35.15	FSF
2009	Oct	24.72	38.23	FSF
2009	Nov	26.46	37.50	
2009	Dec	33.29	45.87	
2010	Jan	32.87	43.79	
2010	Feb	36.94	45.12	
2010	Mar	33.84	42.64	
2010	Apr	28.57	39.13	
2010	May	22.52	35.04	
2010	Jun	27.28	40.07	
2010	Jul	30.57	49.40	
2010	Aug	26.10	44.17	
2010	Sep	24.31	39.98	FSF

[1] Although the experiment did not occur in these months, it still affected these months because water was reallocated within the water year to make enough water available for the experiment.

Decision and Information Sciences Division
Argonne National Laboratory
9700 South Cass Avenue, Bldg. 221
Argonne, IL 60439-4844

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