GLEN CANYON DAM

Colorado River Storage Project, Arizona

THE SHORT-RUN ECONOMIC COST OF ENVIRONMENTAL CONSTRAINTS ON HYDROPOWER OPERATIONS

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David A. Harpman

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Bureau of Reclamation
Technical Service Center
Economics Group (D-8270)
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In October 1995, the operations of Glen Canyon Dam were changed to a new regime known as Modified Low Fluctuating Flows (MLFF). Although the annual and monthly amounts of water released downstream remains unchanged, MLFF imposes a unique and complex set of constraints on hourly and daily hydropower operations. This paper summarizes the background for this decision, reviews some pertinent power system concepts, and develops a modeling framework for valuing hourly hydroelectric generation under varying combinations of constraints. The simulated impact of MLFF is analyzed with this model and the results are discussed.

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THE SHORT-RUN ECONOMIC COST OF ENVIRONMENTAL CONSTRAINTS ON HYDROPOWER OPERATIONS

by

David A. Harpman
Economics Group
Technical Service Center
Bureau of Reclamation
Denver, Colorado

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TABLE OF CONTENTS

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ABSTRACT

In October of 1995, the Secretary of the Interior announced that Glen Canyon Dam would be operated under the Modified Low Fluctuating Flow (MLFF) criteria to protect downstream archeological, cultural, aquatic, and riparian resources. Although the annual and monthly amounts of water released downstream remain the same, MLFF imposes a unique and complex set of constraints on hourly and daily hydropower operations. These constraints include restrictions on ramp rates (hourly rate of change in release), minimum flows, maximum flows, and the daily change in flow. In addition, a key component of MLFF operations is adaptive management which establishes a framework of research and monitoring on which future changes in operation will be based. Consequently, MLFF operations are not static and variants of these hourly constraints may be contemplated in the future. This paper summarizes the environmental concerns which led to MLFF, reviews some pertinent electric power system concepts, and describes current institutional and market conditions. A generalized method for simulating and valuing hourly hydroelectric generation under various operational constraints is then introduced. This approach is then used for an analysis of changing operations at Glen Canyon Dam from historical operations to MLFF. The volume of water released, and hence energy generated, is the same in both cases. Under MLFF, more energy is generated during offpeak periods. Because electricity is most valuable during onpeak hours, this has a significant economic impact. For a representative 11.3 million acre-foot release year, changing to MLFF operations results in a 21 percent loss in generation capacity and a $5 million (6.4 percent) decrease in the short-run

economic value of the energy produced. This estimate reflects the opportunity cost of generating lost onpeak energy at existing thermal power plants. This estimate of short-run incremental cost is, of course, sensitive to the quantity and pattern of water release across the water year, reservoir elevations, and conditions in the electric power market. Nonetheless, it provides policy relevant information for making informed tradeoffs among competing resources.

GLEN CANYON DAM, COLORADO RIVER STORAGE PROJECT, ARIZONA
THE SHORT-RUN ECONOMIC COST OF ENVIRONMENTAL CONSTRAINTS ON HYDROPOWER OPERATIONS

INTRODUCTION

The focus of this paper is on the estimation of the short-run economic impacts of imposing environmental constraints on hydropower operations at Glen Canyon Dam. Glen Canyon Dam is a large hydropower facility on the Colorado River in Arizona just upstream from the Grand Canyon. This facility was designed and operated historically to produce power primarily during onpeak periods when it is most valuable. The production of peaking power at Glen Canyon Dam results in large fluctuations in downstream releases and river stage which have significant adverse impacts on the downstream environment. Recently, a new operational regime called Modified Low Fluctuating Flows (MLFF) was announced which will help to protect and enhance downstream resources. Although the volume of water released annually and monthly downstream remains the same, compared to historical operations, the MLFF criteria impose significant constraints on hourly and daily hydropower operations. The MLFF criteria include adaptive management which establishes a framework of research and monitoring on which future changes in operation will be based. In the short-run, the number and types of generation units is fixed. In the long-run, the number and types of powerplants (e.g., coal, gas, combined cycle) will change to reflect changes in demand, technology improvements, and evolving institutions. Changing to MLFF operations will have significant short-run and long-run impacts on power production.

Current conditions in electricity markets combined with changes in marketing institutions suggest that the substantial excess generating capacity in the Western system will persist for a number of years. Combined with the fluid nature of future operations at Glen Canyon Dam, this dictates a framework which allows for the rigorous analysis of short-run effects. In this paper a generalized methodology for estimating the short-run physical and economic impacts of operational changes is described. This framework is then used to estimate the short-run economic impact of moving from historical to MLFF operations at Glen Canyon Dam.

BACKGROUND

Electricity cannot be efficiently stored on a large scale using currently available technology–it must be produced as needed. Consequently, when a change in demand occurs, such as when an irrigation pump is turned on, somewhere in the interconnected power system the production of electricity must be increased to satisfy this demand. In the language of the utility industry, the demand for electricity is known as "load." Load varies on a monthly, weekly, daily, and hourly basis. During the year, the aggregate demand for electricity is highest in the winter and summer when heating and cooling needs, respectively, are greatest. Load is less in the spring and fall which are known as "shoulder months." During a given week, the demand for electricity is typically higher on weekdays, with less demand on weekends, particularly holiday weekends. During a given day, the aggregate demand for electricity is relatively low from midnight through the early morning hours, rises sharply during working hours, and falls off during the late evening.

Power is most valuable when it's most in demand—during the day when people are awake and when industry and businesses are operating. This period, when the marginal cost of generation is high, is called the "onpeak period." In the West, the onpeak period is defined as the hours from 7 a.m. to 11 p.m., Monday through Saturday. All other hours are considered to be offpeak.

The maximum amount of electricity which can be produced by a powerplant is called its capacity. Capacity is often measured in megawatts (MW). The capacity of thermal powerplants is determined by their design and is essentially fixed. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, the amount of water available for release, and the design of the facility. The rate at which a powerplant can change from one generation level to another is called a "ramp rate." For hydropower plants, this is typically measured by the change in flow, measured in cubic feet per second (cfs), over a 1 hour period necessary to meet load. Ramp rates vary widely depending on the type of powerplant, its design, and possible operational constraints.

Hydropower plants are relatively expensive to construct, but their variable cost of operation is extremely low in comparison to thermal plants. Peaking hydropower plants, such as Glen Canyon, are designed to rapidly change generation levels in order to satisfy changes in the demand for electricity. This capability is termed "load following." Peaking hydropower plants are particularly valuable because they can be used to generate power during onpeak periods avoiding the cost of operating more expensive thermal plants such as gas turbine units. Hydropower plants are also more reliable than thermal plants and do not generate emissions.

GLEN CANYON DAM AND THE COLORADO RIVER STORAGE PROJECT

Glen Canyon Dam was completed by the Bureau of Reclamation in 1963. This 710-foot high concrete-arch dam controls a relatively arid drainage basin of approximately 108,335 square miles. Glen Canyon Dam forms Lake Powell, which is 186 miles long and has an active storage capacity of 20.876 million acre feet (maf). There are eight hydroelectric generators at the dam, which can produce up to 1,288.2 MW of electric power. The design of this facility allows for nearly instantaneous response to changes in load. Historically, it has been operated primarily to produce power during onpeak periods.

Glen Canyon Dam is an integral part of the Colorado River Storage Project (CRSP) which was authorized in 1956. As dictated by Public Law 90-537, monthly and annual release volumes for all major CRSP facilities are established at the beginning of the water year, which runs from October to September, based on projected hydrologic conditions as described in the Annual Operating Plan (e.g., see Reclamation 1995b). These forecast releases are then adjusted during the water year to reflect actual inflow conditions. Annual and monthly releases made from the dam are consistent with the “law of the river” and Long-Range Operating Criteria which includes an objective 8.23-maf minimum annual release and equalized storage between Lake Powell and Lake Mead which is located downstream. Annual releases greater than the minimum are permitted to avoid anticipated spills and equalize storage. Although power production at CRSP facilities is “incidental” to other project purposes, the distribution of monthly release volumes across the water year reflects the periods when electricity is most in demand and therefore most valuable. An excellent compendium and reference to CRSP operations, pertinent treaties, and regulations which comprise the “law of the river” is found in Reclamation (1980).

The electricity from CRSP is marketed by the Western Area Power Administration (Western) as part of the Salt Lake City Area Integrated Power (SLCA/IP) system. There are 12 hydroelectric facilities in the SLCA/IP system, with a combined generation ability of 1,796.6 MW. The Glen Canyon hydropower facility makes up approximately 72 percent of the installed capacity of this system.

The power produced in the SLCA/IP system and purchased by Western from other sources is sold primarily to about 180 long-term, firm power customers, which in turn, serve approximately 1.7 million (30 percent of the total) residential, industrial, agricultural, and municipal end-use consumers across a six state area which includes Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. This power is provided to Western's customers under contracts which establish the terms for how capacity and energy are to be sold. The capacity and energy level is called firm when it is guaranteed to customers. These contractual arrangements, the methodology used for determining firm capacity and energy levels, and the amount of energy and capacity allocated to each customer are described in detail in Western (1989, 1996).

ENVIRONMENTAL CONCERNS AT GLEN CANYON DAM

Historically, Glen Canyon Dam was operated primarily to produce power during onpeak periods. Operation of the dam to produce peaking power results in significant hourly fluctuations in release and river stage. These fluctuations have been shown to significantly affect the quality of whitewater boating, angling, and the maintenance of the downstream trout fishery (GCES 1988, National Academy of Sciences 1987). They have also been shown to significantly affect aquatic resources and sediment deposits on the channel margins. The elimination of sediment laden floods has prevented the replenishment of high predam terrace deposits. Species which evolved in a warm, sediment rich environment now face cold, clear conditions in addition to large daily fluctuations in flow and river stage. Three long-lived native fish species have been extirpated and two others, the humpback chub and the razorback sucker, are now endangered (Reclamation 1995).

The Operation of Glen Canyon Dam Environmental Impact Statement (GCDEIS) was initiated in 1989 to examine options which, "... minimize–consistent with law–adverse impacts on downstream environmental and cultural resources and Native American interests... ." The environmental impacts of nine operational alternatives, ranging from unrestricted operations to baseloading of the powerplant, were examined in the final GCDEIS (Reclamation 1995).

On October 9, 1996, Secretary of the Interior, Bruce Babbit, issued a record of decision (ROD) on future operations of Glen Canyon Dam. He announced that the facility will be operated according to MLFF. Under MLFF there are new restrictions on maximum flows, minimum flows, ramp rates, and the daily change in flow. Table 1 compares historical and MLFF operating criteria.

TABLE 1. HISTORICAL AND MLFF OPERATING CRITERION

	Historical Operation Criteria	Modified Low Fluctuating Flow[1]
Minimum Releases (cfs)	1,000 Labor Day-Easter 3,000 Easter-Labor Day	8,000 between 7 a.m. and 7 p.m. 5,000 at night
Maximum Releases[2] (cfs)	31,500	25,000[3]
Allowable Daily Flow Fluctuations (cfs/24 hours)	Unrestricted	5,000[4] 6,000 or 8,000
Up-Ramp Rates (cfs/hour)	Unrestricted	4,000
Down-Ramp Rates (cfs/hour)	Unrestricted	1,500

[1]Non-operational elements and periodic special releases such as beach-building and habitat-maintenance flows are not included in this table. See Reclamation (1995) for details.
[2] Maximums may necessarily be exceeded during high-water release years.
[3] Will be exceeded during beach-building and habitat-maintenance flows.
[4] Daily fluctuations are limited to 5,000 cfs for monthly release volumes less than 600,000 acre-feet; 6,000 cfs for monthly release volumes of 600,000 to 800,000 acre-feet; and 8,000 cfs for monthly volumes over 800,000 acre-feet.

The MLFF Operating Criteria shown in Table 1 were designed to reduce daily flow fluctuations well below historic levels. Minimum flows, maximum flows, ramp rates, and allowable daily fluctuations were established with the goal of protecting downstream resources while allowing limited flexibility for power operations.

Within these criteria, the actual minimum and maximum releases from the dam during any given day depend on the monthly release volume, the allowable daily fluctuation, and the demand for hydroelectric power. Actual releases are usually higher than the minimum and lower than the maximum allowed. The minimum release is maintained higher during the daytime hours to protect the aquatic food base from exposure. The maximum release was set to reduce sand transport in the river and to accumulate sand along the riverbed. The allowable daily fluctuation (either 5,000, 6,000, or 8,000 cfs/24 hrs) depends on the monthly release volume and was determined so that the maximum daily change in river stage would be nearly the same during all months–about 3 feet in most reaches. The down-ramp rate was set to reduce seepage based erosion of sandbars and to avoid stranding fish. The up-ramp rate was set to reduce potential operation-related impacts to canyon resources.

A key component of MLFF is adaptive management. Adaptive management is a process, "...whereby the effects of dam operations on downstream resources would be assessed and the results of those resource assessments would form the basis for future modifications of dam operations. Many uncertainties still exist regarding the downstream impacts of water releases from Glen Canyon Dam. The concept of adaptive management is based on the recognized need for operational flexibility to respond to future monitoring and research findings and varying resource conditions (Reclamation 1995)."

To date, the adaptive management approach has been tried in three separate arenas, all in the Pacific Northwest. The most notable of these applications is the Columbia River Basin Program of the Northwest Power Planning Council. There is a rich literature on the political, economic, and biological strengths and failings of adaptive management in this context. A narrative history and assessment of the Pacific Northwest experience can be found in Lee (1993). Wieringa and Morton (1996) provide some analysis and perspective on adaptive management in the Grand Canyon.

As outlined in the GCDEIS, a Federally chartered advisory group known as the Adaptive Management Work Group (AMWG) has been formed to assist Reclamation with adaptive management. The AMWG is comprised of a diverse group of interests which includes representatives from Federal and State agencies, the seven Colorado River Basin states, Native American tribes, environmental groups, recreation interests, and contractors for Federal power. To support adaptive management, the Grand Canyon Monitoring and Research Center was established to facilitate long-term monitoring and research on downstream resources.

MLFF AND HYDROPOWER OPERATIONS

The MLFF operational criteria have several effects on hydropower operations. First, the constraint on maximum flows reduces the capacity at Glen Canyon Dam. Under historical operations, releases were limited by the design of the plant to 31,500 cfs, which produces 1,288 MW when the reservoir is full. Under the MLFF alternative, the maximum flow is limited to 25,000 cfs, or 1,022 MW when the reservoir is full—a loss of 266 MW[1]. The ramp rate, minimum flow, and maximum daily change constraints combine to limit the ability of the hydropower plant to respond to changes in load.

The volume of water released during the month is unaffected by the change to MLFF and consequently the amount of energy generated is unchanged. However, compared to historical operations, the time when this energy is produced is fundamentally changed. Under MLFF, less energy is generated during the onpeak hours and more energy is generated during the offpeak hours when it is less valuable.

PREVIOUS STUDIES

The Glen Canyon Environmental Studies Power Resources Committee has undertaken several analyses of the long-run economic impacts of proposed changes in the operation of Glen Canyon

[1]This simple example illustrates the theoretical capacity effects which result from this maximum flow constraint. However, it is the effects on so called "marketable capacity" which are of primary concern. Marketable capacity is determined by a probabilistic procedure described in Western (1989).

Dam (Power Resources Committee 1993, 1995). Using the Electricity Generation Expansion Analysis System (EGEAS), an industry standard production expansion model (Electric Power Research Institute 1996), the Power Resources Committee estimated that the annualized economic cost of changing from historical operations to MLFF was 34.8 million dollars (1991 nominal dollars) per year (Power Resources Committee 1996). Due to the presence of substantial excess capacity in the system now and in the immediate future, the bulk of these costs are projected to be incurred in the latter years of the 50-year analysis period. These future costs primarily reflect the accelerated construction of planned generation additions and the incremental costs associated with their operation.

The EGEAS model is not inherently capable of simulating hourly release constraints such as ramp rate limits and the maximum daily change constraint. Consequently, considerable pre-processing of the input data was carried out in the effort to characterize the effects of these constraints. Subsequent review of these studies by the General Accounting Office (GAO), suggests the estimated results did not fully capture the effects of shifting generation from onpeak to offpeak periods (GAO 1996). It should be noted however, that the studies undertaken by the Power Resources Committee were designed to estimate impacts over a 50-year analysis period, rather than to provide a rigorous accounting of near-term effects. As with all such studies, the magnitude of the estimates obtained is highly sensitive to load growth assumptions, interest rate assumptions, projections of real fuel escalation rates, the assumed cost, nature, and efficiency of future powerplants, and, perhaps most importantly—institutional assumptions.

INSTITUTIONAL CHANGE AND MARKET CONDITIONS

Sweeping changes in the functioning of electric utility industry and the manner in which electricity is marketed are occurring and are expected to continue. In 1995, the Federal Energy Regulatory Commission (FERC) issued orders 888 and 889 (FERC 1995). These two orders form the basis for a complete restructuring of the electric utility industry. Order 888 opens up wholesale power sales to competition. It requires public utilities owning, controlling, or operating transmission lines to file nondiscriminatory open access tariffs that offer other entities the same transmission service they provide themselves. Order 889 establishes standards of conduct and requires utilities to post information about their available transmission capacity on real-time computer systems.

As of the date of this analysis (early 1997), the electricity market in the region where CRSP power is sold is characterized by the presence of substantial amounts of surplus generation capacity. Open access to transmission lines has enabled wholesale purchases of power from lower cost sources. Advances in technology, particularly in gas turbine peaking power units, as well as aggressive cost cutting by major investor owned utilities, have put downward pressure on wholesale prices (Energy Information Administration 1996). Current spot market prices in the region are relatively low—perhaps below the variable production costs of some producers. Regional forecasts of load growth have declined and a number of power plant construction projects have been canceled or postponed. A substantial proportion of the net additions to generation in the region are “re-powers” or upgrades of existing facilities (Western Systems Coordinating Council 1996). There are extensive discussions in both industry and regulatory circles about “stranded costs,” or fixed costs that would be unrecoverable if customers abandon their current utilities in favor of less costly suppliers (e.g., see Madian 1997 or Abel and Parker 1997). Moreover, a recent report by Western suggests the least cost method of replacing the capacity lost at Glen Canyon Dam by moving to MLFF is through open-market purchase rather than construction of new facilities (Western 1995). It seems likely these short-run conditions will persist for a number of years. Against this backdrop, long-run presumptions about load growth, interest rates, real fuel escalation rates, the cost, nature, and efficiency of future powerplants, and, marketing institutions, seem quite speculative.

THE ROLE OF SHORT-RUN ANALYSES

Adaptive management combined with the dynamic nature of electricity markets suggest short-run economic analyses will play an important role in the decision making process (National Academy of Sciences 1996). Under adaptive management, it is highly likely that changes in the operation of Glen Canyon Dam will be contemplated—perhaps quite frequently. Furthermore, some of these contemplated changes may be of limited duration. Although the nature and scope of potential changes cannot be entirely foreseen, one such change has already been suggested. Some observers have noted MLFF operations at Glen Canyon Dam may be more restrictive than necessary to protect downstream resources. The up-ramp constraint is of particular concern. As shown in Table 1, the up-ramp rate for MLFF is 4,000 cfs/hour. Although this constraint was initially established to protect canyon resources, no subsequent scientific evidence supporting an up-ramp rate limit has yet emerged (Reclamation 1996). Potentially, the AMWG could entertain an examination of the potential impacts of changing the up-ramp rate to, for example, 10,000 cfs/hour.

ECONOMIC VALUE OF HYDROELECTRICITY

Historically, the electric utility industry has been heavily regulated by both State and Federal regulatory agencies. Transactions between utilities tend to be shaped by regulatory policy and therefore often fail to reflect economic value. In the absence of meaningful economic price data, the avoided cost, or the cost of the next least cost alternative source of supply has commonly been used as a proxy for the economic value for hydropower (Young and Gray 1972, Gibbons 1986).

The operational changes examined here result in hourly changes in the timing of hydropower generation. Analysis of the economic impact of these changes requires price data which is temporally comparable. Obtaining detailed site specific price data for analysis purposes has, up until quite recently, been extremely problematic. In the absence of hourly data, two methods were often used to construct vectors of economic value for analysis purposes—assumption and modeling. By far the most commonly used approach is to make an assumption about the economic value of onpeak and offpeak power. Although convenient, the validity of these assumptions were are easily questioned and it is difficult to defend them on empirical grounds. Alternatively, models such as the Spot Market Network Model (VanKuiken, et al. 1994) or commercially available production cost models such as PROSYM (The Simulation Group 1995) can be used to estimate a price vector suitable for analysis. These models are both data and resource intensive. Although the models are quite rigorous, the results obtained with both price forecasting models and production cost models are highly sensitive to the characterization of the power system, load growth assumptions, fuel costs, and escalation rates.

Detailed, site specific, spot market prices for electricity have recently become available. Since FERC orders 888 and 889 were issued, wholesale transactions of electric power have become commonplace. Electricity has become a commodity much like oil, natural gas, pork, and wheat. In March 1996, a futures market for wholesale bulk electricity traded at two locations which was established on the New York Mercantile Exchange (NYMEX). Both forward and current market prices for electricity are now more readily observed. At a given location and time, these observable market prices embody all of the characteristics of the interconnected power system which heretofore could be approximated only with complex models. These prices reflect actual market transactions thus obviating the need for proxy measures or estimates derived using models.

ANALYSIS APPROACH

A three-step process was used for estimating the economic impacts described in this analysis. First, historical and MLFF generation at Glen Canyon Dam was simulated on a monthly basis for each hour in water year 1996 (8,760 hours). Second, the resultant vectors of historical and MLFF hourly generation were evaluated using spot market prices. Finally, the hour by hour difference in economic value was computed.

Simulating Hydrogeneration

Given knowledge about the generation resources owned by competitors, the expected aggregate demand or load, the amount of water available for release, regulatory constraints, and the engineering limitations of their own plant, the problem faced by the profit maximizing hydropower producer is to generate as much power as possible during the onpeak hours, when it is most valuable. Hourly releases from the dam, q_h , are the variable under management control. The objective is to reduce the peaks in the aggregate demand curve by using hydropower to supply energy at periods when the demand is greatest. The remaining load is met by coal, nuclear, gas, and oil plants which are more expensive to operate and/or respond to changes in demand more slowly.

The environmental constraints on hydropower operations at Glen Canyon Dam, consisting of ramp rate constraints, a maximum daily change constraint, and a time varying minimum flow constraint, are unique and outside the capability of most existing hydropower models. Simple constraints on minimum and maximum flows at hydropower facilities are relatively common and many existing power models are capable of characterizing them. However, the time varying minimum flow constraint and the constraint on the maximum daily change in flow are, as far as is known, unique to this application. While ramp rate restrictions have been investigated in the context of thermal plants (Lee, Lemonidis, and Liu 1994), similar analyses for hydropower facilities have not been reported in the literature. The nature and number of these restrictions introduce considerable complexity to this analysis.

In concept, a constrained multiperiod optimization problem is readily solved using familiar techniques such as discrete dynamic programming (DDP) or multiperiod linear programming (MPLP). However, these particular release constraints present an additional challenge. For example under MLFF, the up-ramp rate constraint implicitly limits the flow in hour (h+1) to the flow in hour (h) plus 4,000 cfs. This constraint violates the premise of sequentially independent decisions and expands the state space for DDP analyses beyond feasible limits. In contrast, MPLP can be employed to solve a problem with constraints of this form. However, the number of hourly periods in each month (744) and the nature of the maximum daily change constraint combine to produce an extremely daunting computational exercise. At the expense of some rigor, the size of the problem can be reduced by analyzing a "typical week" rather than all hours in the month (Veselka, Hamilton, and McCoy 1995).

The peakshaving algorithm, one of two widely used approaches for simulating hydropower generation, allows for the efficient formulation and solution of this specialized problem. A discussion of the use of this algorithm and a comparison with other hydropower dispatch algorithms can be found in Staschus, Bell, and Cashman (1990). Versions of the peakshaving algorithm, without constraint simulation capabilities, are available in a number of commercial power system models including PROSYM (The Simulation Group 1995)[2]. The peakshaving algorithm has been extended by

[2]A recent version of PROSYM allows for ramp rate restrictions.

EDF for use in ELFIN (EDF 1996). This extension allows for ramp rate constraints, time varying minimum and maximum flow constraints, and a maximum daily change constraint. The model used in this application is based on EDF's implementation, but has been further extended to allow for varying reservoir elevations and to represent the physical and engineering features of the Glen Canyon Dam and powerplant in detail.

As with most real world applications, a common metric is needed to formulate the peakshaving model. To facilitate these conversions, three functions are employed. The first function, fe[q_h,elevation], calculates the energy produced in hour h by flow q at a given reservoir elevation. This function is described in Appendix 1. The second function, ef[·], is used to calculate the flow, q, required to produce a given amount of energy (MW) at a particular reservoir elevation. This relationship is obtained by solving the equation shown in Appendix 1 for flow, q_h. The third function, fv[·], converts a flow measured in (cfs) to an equivalent volume measure (af).

The function describing the optimal series of hourly flows, $q_h(x)$, œ$_h$ 0 {1,2,3,...H}, is shown in (1). Note that $q_h(x)$ is discontinuous and monotonically decreasing in x. In equation (1), expected aggregate load in hour (h) is L_h, the maximum generation release (capacity) is c,

$$q_h(x) = \begin{Bmatrix} minf_h, & if\ ef[L_h] \le x \\ ef[L_h] - x, & if\ x \le ef[L_h] \le x + c \\ c, & if\ ef[L_h] \ge x + c \end{Bmatrix}$$

and x is an arbitrary level of flow or release.

The peakshaving algorithm uses an iterative binary search routine to find an x which uniquely

$$\sum_{h=1}^{H} fv[q_h(x)] = mvol$$

$$st:$$

$$q_h(x) q_{h+1}(x) \le uprate$$

$$q_{h+1}(x) q_h(x) \le downrate$$

$$q_h(x) \le c$$

$$q_h(x) \ge minf_h$$

satisfies equation (2), subject to the set of constraint equations (3 through 8):

$$\max(q_h(x)...q_{h+k}(x))\min(q_h(x)...q_{h+k}(x)) \leq mdc$$

$$c = \min(maxfc, potential\ \ flow)$$

Where:

q_h = power release (cfs) at hour h.
L_h = expected aggregate load (mw) at hour h
maxfc = maximum flow constraint for the alternative (cfs).
$minf_h$ = minimum flow constraint in hour h for the alternative (cfs).
uprate = up-ramp rate (cfs).
downrate = down-ramp rate (cfs).
max() = maximum operator
min() = minimum operator
mdc = maximum daily change constraint for the alternative (cfs).
mvol = volume of water available for release during the month (af).
potential flow = the maximum flow which can physically be passed through the generators at a given lake elevation.
k = min(24,H-h)

Equation (2) is the water balance equation. This equation ensures that aggregate hourly releases equal the total amount of water available for release during the month. Equations (3) and (4) are the up-ramp and down-ramp constraints, respectively. Equation (5) is the maximum daily change constraint. For MLFF, this constraint varies with the amount of water released during the month. Equations (6) and (7) jointly define the maximum flow constraint, which for MLFF is the lesser of 25,000 cfs or the greatest amount of water which can physically be released given the elevation of the lake. Under MLFF, the minimum flow constraint varies by time of day and is described by equation (8). In addition to constraint equations (3 through 8), there are a number of other physical and engineering constraints which are not shown. These additional constraints are not explicitly described since they are common to both alternatives and are not binding except under unusual circumstances.

Valuation

$$VAL = \sum_{h=1}^{H} gen_h * price_h$$

Given, q_h , the optimal release in any hour h, the corresponding optimal hourly generation is $gen_h = fe[q_h, elevation]$ as shown in Appendix 1. The economic value of this generation over all hours in the month, VAL, is then given by equation (9).

INPUT DATA AND SOURCES

Hydrologic Data

Annual and monthly releases at Glen Canyon Dam are quite variable due both to management decisions and to the stochastic nature of inflows. An extensive discussion of inflows and historical releases can be found in Reclamation (1994, Appendix). This analysis is based on a representative water year with an annual release of 11.3 maf. The monthly release volumes and end-of-month (EOM) reservoir elevations for this representative release year are shown in Table 2. As shown in Table 2, monthly releases from Glen Canyon Dam are patterned to correspond with the times of the year when electricity demands are highest—summer and winter.

TABLE 2. REPRESENTATIVE MONTHLY RELEASE VOLUMES AND RESERVOIR ELEVATIONS FOR GLEN CANYON DAM

	Monthly Volume (af)	End-of-Month Reservoir Elevation (ft)
October	850,000	3685.4
November	900,000	3683.7
December	950,000	3681.6
January	1,100,000	3677.7
February	950,000	3674.8
March	850,000	3673.2
April	825,000	3673.8
May	875,000	3681.2
June	1,000,000	3690.5
July	1,050,000	3691.6
August	1,100,000	3688.4
September	850,000	3686.3
TOTAL	11,300,000	

Aggregate Load Data

In this analysis, an aggregate hourly load curve was assumed to represent system demand during water year 1996. This aggregate load curve was constructed from 1994 hourly load data reported by Salt River Project, Platte River Power Authority, Colorado Springs Utilities, and Deseret Generation and Transmission. This publicly available data was obtained from information provided to the FERC on form 714. The 1994 load data was escalated by 2 percent per annum to account for load growth and adjusted for the number of days and the pattern of weekdays and weekends in 1996.

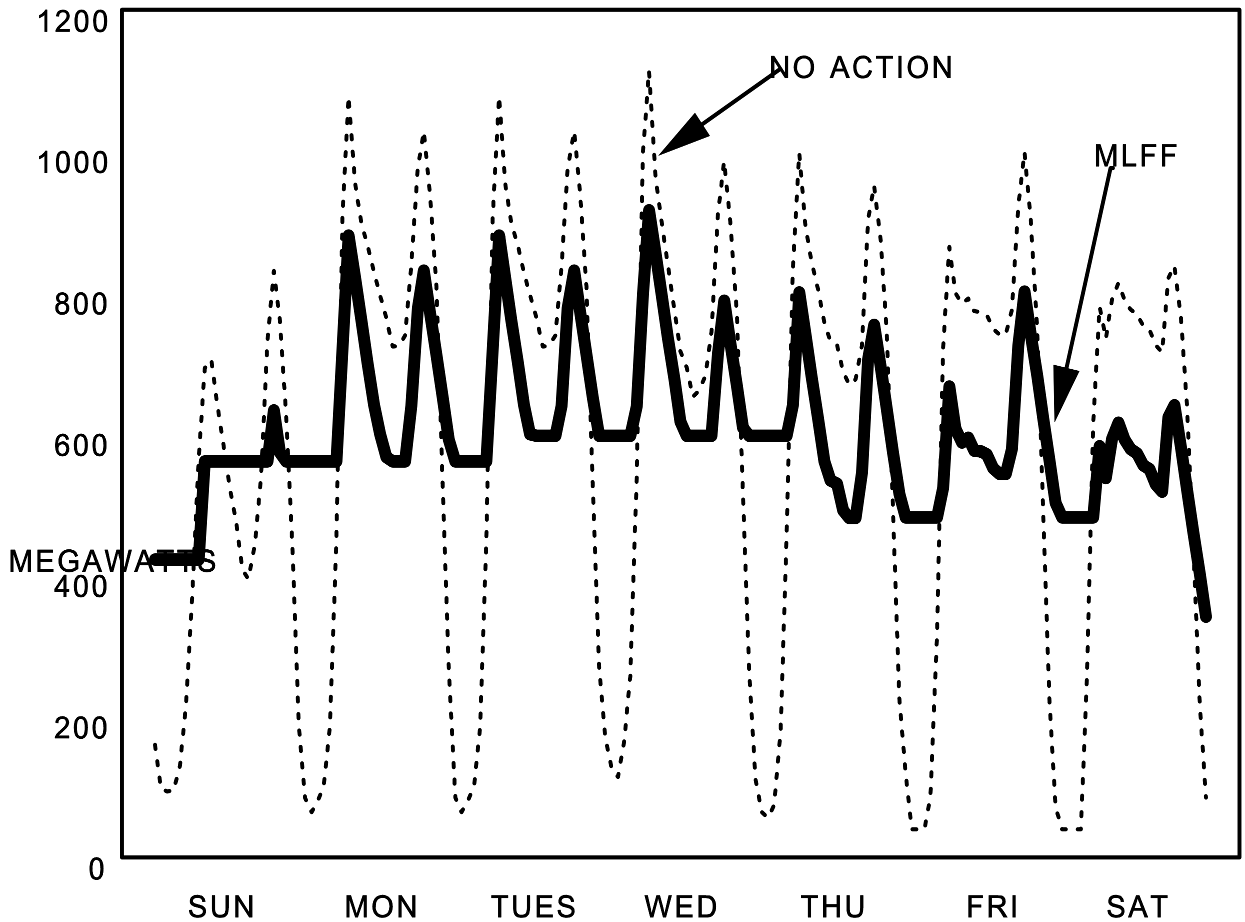
Spot Market Price Data

Daily onpeak and offpeak spot market (non-firm) prices were used to value the simulated generation for this analysis. These data are specific to the Palo Verde and Westwing, Arizona interchange. This location near Phoenix is a transaction accounting point for electricity which is ultimately used elsewhere in the Southwest and is a delivery point for futures contracts sold on the NYMEX. The price data for October 1995 through December 1995 were obtained from Economic Insight, Inc. These data represent the price of wholesale bulk onpeak and offpeak power scheduled for delivery the next day. The data for January 1996 through September 1996 were furnished for this analysis by the Dow Jones and Company, Inc. Energy Service (Dow Jones). Through contractual arrangement, Dow Jones obtains real-time onpeak and offpeak transaction data from a number of participating utilities and power wholesalers. These proprietary data are then sales volume weighted. Daily weighted average onpeak and offpeak prices are made available to subscribers of the Dow Jones Telerate Service and are later published in *The Wall Street Journal*. These data represent actual observations of electricity prices at a level of accuracy, spatial location, and disaggregation which was heretofore unavailable. Descriptive statistics for these data are found in Appendix 2

RESULTS

Using the aggregate load data previously described, the constraints shown in Table 1, and the monthly release volumes and reservoir elevations shown in Table 2, the peakshaving model was used to simulate generation at Glen Canyon Dam under both historical operations and MLFF for all months during the representative water year. Figure 1 illustrates the results of this simulation for 1 week in March 1996. As shown in this figure, under MLFF's the maximum generation (capacity) is less than that under historical operations, the minimum generation level is higher and the amount of change during any given day is greatly reduced. By carefully examining Figure 1, it is also possible to see the effects of restrictions on ramp rates—under MLFF operations, the ability to follow load is reduced. This is particularly evident when down-ramping. The amount of water released in any given month is identical under both historical operations and MLFF. For this reason, the amount of energy generated is the same. However, compared to historical operations, the capacity under MLFF is somewhat reduced. Under historical operation criteria, the summer (April through September) capacity is 1,300 MW and the winter (October through March) capacity is 1,286 MW for this representative water year. Under MLFF, both the summer and winter capacity is reduced by 20.6 percent to 1,032 and 1,020 MW, respectively. This capacity reduction results from the maximum flow constraint. If monthly release volumes were lower, other constraints or combinations of constraints would be binding.

The maximum daily change constraint is particularly onerous under low release volume conditions.



Using the daily onpeak and offpeak spot market prices summarized in Table 3, the economic value of this simulated generation was calculated. Monthly estimates of economic value are shown in Table 4. As shown in this table, shifting generation from onpeak to offpeak periods reduces the economic value of the electricity generated by $5,094,325 for this representative water year. This amounts to a reduction of 6.4 percent.

TABLE 4. SIMULATED HISTORICAL AND MLFF ECONOMIC VALUE BY MONTH

	Historical ($)	MLFF ($)	Difference ($)
October	5,940,911	5,697,534	(243,377)
November	5,899,231	5,702,439	(196,792)
December	5,190,557	5,000,906	(189,651)
January	7,270,507	7,074,289	(196,217)
February	5,458,053	5,199,146	(258,907)
March	4,513,208	4,276,201	(237,007)
April	5,284,892	4,901,960	(382,932)
May	5,019,777	4,561,698	(458,084)
June	6,763,103	6,117,219	(645,884)
July	9,349,733	8,461,160	(888,573)
August	11,611,127	10,710,067	(901,060)
September	7,007,667	6,511,828	(495,842)
TOTAL	79,308,767	74,214,443	(5,094,325)

LIMITATIONS

The short-run estimates of economic value presented here are sensitive to the quantity and pattern of water release across the year, reservoir elevations, and conditions in the electric power market which are reflected by spot market prices. This short-run estimate of cost is not intended to capture the incremental cost of any additional generation facilities which might need to be built at some time in the future as a result of changed operations. Therefore, these estimates are inappropriate for use in long-run planning studies. These estimates are based on an underlying optimization model. Unlike an optimization model, human operators do not have perfect foresight. This makes it unlikely that actual operations will duplicate simulated operations. Furthermore, the modeling framework used here simulates the operation of Glen Canyon Dam in isolation from the other CRSP units. Admittedly, the opportunity to manage other CRSP units in a discretionary manner is limited. However, to the extent that operational flexibility exists, these units could be used to partially offset the power system impacts of environmental constraints at Glen Canyon Dam. Finally, this analysis is restricted to direct power system impacts. Although the operation of Glen Canyon Dam also affects recreation use value (Bishop, et al. 1987), total economic value (Harpman, Welsh, and Bishop 1995, Welsh, et al. 1995), regional impacts (Douglas and Harpman 1995), and air quality in the region (Reclamation 1995, Power Resources Committee 1996), these topics are not addressed here.

CONCLUSION

In order to, "...minimize—consistent with law—adverse impacts on downstream environmental and cultural resources and Native American Interests... ," the Secretary of the Interior has determined that Glen Canyon Dam will be operated under the MLFF regime. Under MLFF, hydropower operations are greatly restricted compared to historical operations. These restrictions include constraints on ramp rates, minimum flows, maximum flows, and the maximum daily change in flows. An important element of MLFF is adaptive management. Adaptive management establishes both a framework and a process for examining future operational changes. Consequently, MLFF is by no means a static regime and operational changes must be anticipated in the future.

This paper describes an hourly framework for estimating the short-run economic costs of introducing a particular set of hourly constraints on hydropower operations at Glen Canyon Dam. As described, this approach is suitable for the analysis of the impacts of a wide-range of hourly constraints. Moreover, it is quite rigorous and less costly than comparable frameworks. Within the limitations described, this methodology can produce results which, in conjunction with research findings linking the effects of dam operations to changes in the downstream ecosystem, are critically important for management decision making.

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APPENDIX 1. FLOW, HEAD, AND GENERATION

Power generation at Glen Canyon Dam in megawatts (MW) is calculated from flow and reservoir elevation as shown in the equation below:

$$fe[flow, elevation] = \frac{\Gamma * eff * flow * head(elevation)}{hptokw * 1000}$$

Where:

Γ = 62.40, The specific weight of water at 50 degrees Fahrenheit (lbs/ft^3).
eff = 0.88872889 efficiency factor (dimensionless).
head(A) = effective head (feet).
flow = Water release (cfs).
hptokw = 737.5, Conversion factor (kw/ft-lbs).

The methods described in Reclamation (1988, sections 3.38.2-3.38.5 and 1987, sections 9.1-9.2) are used to calculate effective head.

APPENDIX 2. DESCRIPTIVE STATISTICS—SPOT MARKET PRICES

	ONPEAK PRICES [1] ($/MWhr)			OFFPEAK PRICES ($/MWhr)		
	MIN	MEAN	MAX	MIN	MEAN	MAX
October	13.50	14.42	15.75	10.50	11.84	15.50
November	12.00	14.24	16.50	8.50	11.19	14.50
December	9.00	11.99	13.75	7.00	8.76	12.50
January	9.61	14.76	21.00	8.60	10.58	17.21
February	8.82	12.85	21.31	5.39	8.27	14.38
March	8.24	11.72	16.22	5.43	8.53	11.52
April	10.03	14.14	17.97	5.52	8.71	13.58
May	7.86	12.44	16.32	4.98	8.18	14.07
June	10.80	14.48	23.08	6.70	9.04	17.14
July	9.84	18.87	23.65	8.37	12.03	21.57
August [2]	14.14	22.17	46.19	9.39	15.19	56.85
September	13.52	17.60	26.75	10.06	12.79	16.96

[1] Onpeak hours are defined as the hours from 7 a.m. to 11 p.m., Monday through Saturday.
[2] The power system disruption of August 10-12, 1996, is responsible for the high maximum onpeak and offpeak spot market prices shown here.