Assessing the Short-Run Economic Cost of Environmental Constraints on Hydropower Operations at Glen Canyon Dam

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ABSTRACT. *Environmental externalities resulting from the construction and operation of a number of hydropower plants are now being reexamined. The focus of many recent analyses is on identifying new, often more restrictive, operational regimes which will improve downstream environmental conditions. These new regimes may create significant market and nonmarket benefits but constraints on hydropower operations frequently lead to economic costs. This paper introduces an hourly constrained optimization framework for estimating the short-run costs of restricting hydropower operations. Glen Canyon Dam, on the Colorado River in Arizona, is used as a case study. Newly available market-based prices are employed.* (JEL Q25)

I. INTRODUCTION

Hydropower plants produce electricity without burning fossil fuels and producing air pollution and are sometimes thought of as environmentally benign. In fact, large hydropower facilities have blocked the spawning of anadromous and migratory aquatic species, eliminated the downstream transport of sediment, fundamentally altered the seasonal hydrograph, affected water chemistry, and, changed the downstream temperature regime (Collier, Webb, and Schmidt 1996). Furthermore, the daily operations of these units, particularly units used to produce peaking power, may have a number of adverse effects on aquatic and riparian communities (Nilsson, Jansson, and Zinko 1997).

The environmental externalities resulting from the construction and operation of a number of hydropower plants are now being re-examined. Nationwide, Federal Energy Regulatory Commission (FERC) licenses to operate 520 hydropower plants have, or will, expire between 1997 and 2010 (Hunt and Hunt 1997). In addition to relicensings, endangered species concerns have lead to the reassessment of a number of other facilities. Although dam removal is an option in some cases (Loomis 1996), the focus of many recent analyses is on identifying new operational regimes which will result in improved downstream environmental conditions. These new regimes may well create significant market and nonmarket benefits but the resultant constraints on hydropower operations inevitably lead to economic costs of varying magnitudes.

This paper introduces an hourly constrained optimization framework for analyzing the effects of environmental constraints on hydropower operations. The short-run economic cost of these impacts is determined using market-based prices. Glen Canyon Dam, located on the Colorado River in Arizona, is used as a case study.

II. 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

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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.

Electric energy 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 demand is highest, is called the "on-peak period." In the West, the on-peak period is defined as the hours from 7:00 A.M. to 11:00 P.M., Monday through Saturday. All other hours are considered to be off-peak.

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 one hour period. Ramp rates vary widely depending on the type of powerplant, its design, and possible operational constraints.

Ignoring pumped storage facilities, there are two principle types of hydropower plants. These are run-of-river plants and peaking plants. Run-of-river plants typically have little water storage capability. Consequently, generation at run-of-river plants is proportional to water inflow and there is little variation in electrical output during the day. Peaking hydropower plants, such as the one at Glen Canyon, often have significant water storage capability and are designed to rapidly change output levels in order to satisfy changes in the demand for electricity. Peaking hydropower plants are particularly valuable because they can be used to generate power during on-peak 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.

III. ECONOMIC VALUE OF HYDROELECTRICITY

The economic value of operating an existing hydropower plant is measured by the avoided cost of doing so. In this context, avoided cost is the difference between the cost of satisfying the demand for electricity, with and without operating the hydropower plant. Conceptually, avoided cost is the savings realized by supplying electricity from a low-cost hydropower source rather than a higher-cost thermal source. These savings arise because the variable cost of operating a hydropower plant is relatively low in comparison to thermal units. For example, the variable costs of operating an average hydropower plant in 1995 was $5.89 per megawatt hour (MWhr). In contrast, the variable cost of operating the average fossil-fuel steam plant was $21.11 per MWhr and the variable cost of operating the average gas turbine peaking unit was approximately $28.67 per MWhr (Energy Information Administration 1996b).

The economic value of operating an existing hydropower plant varies considerably with time of day. The variable cost of meeting demand varies on an hourly basis depending on the demand for electricity, the mix of plants being operated to meet demand, and their output levels. During off-peak periods, demand is typically satisfied with lower cost coal, run-of-river hydropower, and nuclear units. During on-peak periods, the additional load is met with more expensive sources such as gas turbine units. Consequently, the economic value of hydropower is greatest during the hours when the demand for electricity, and the variable cost of meeting demand, is the highest.

If the variable cost of purchasing an additional megawatt of electricity from a least cost source were observable in the market, the economic value of producing hydroelectricity could be readily determined. For example, assume that the cost of purchasing a megawatt of electricity, from the least cost source was $30.00 in a particular hour, and the cost of producing a megawatt of hydroelectricity was $6.00. Then, the avoided cost or economic value of producing an additional megawatt of hydropower at that time would be ($30.00 − $6.00) or $24.00.

IV. GLEN CANYON DAM AND THE COLORADO RIVER STORAGE PROJECT

Glen Canyon Dam was completed by the U.S. Bureau of Reclamation in 1963. This 710-foot high concrete arch dam forms Lake Powell, which is 186 miles long, and has an active storage capacity of 20.876 million acre feet (maf). There are 8 hydroelectric generators at the dam, which can produce up to 1,288.2 megawatts (MW) of electric power.

Glen Canyon Dam is an integral part of the Colorado River Storage Project (CRSP). Based on projected hydrologic conditions, monthly and annual release volumes for all major CRSP facilities are established by the Annual Operating Plan at the beginning of the water year, which runs from October to September. Releases are then adjusted during the water year to reflect actual inflow conditions. Hydropower production at CRSP facilities is "incidental" to all other purposes including international treaty obligations, basin storage, municipal and industrial uses, agriculture, flood control, and fish and wildlife uses. CRSP operations, pertinent treaties, and regulations which comprise the "Law of the River" are described in Nathanson (1980).

The power produced at Glen Canyon Dam is sold by Western Area Power Administration (Western) to approximately 100 entities across a six-state area including Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. These entities are primarily state and federal reservations, rural electric cooperatives, and public utilities. Western operates the Western Area Upper Colorado (WUAC) control area. As the WUAC area operator, Western reserves approximately 56 MW in order to provide immediate response to changes in control area loads. Western also provides system regulation, voltage, and frequency support to Farmington, New Mexico, and seven small utility systems. Currently, CRSP power is marketed as a composite or "bundled" good. In addition to generation, this bundled good includes system regulation, reserves (spinning, non-spinning, and replacement), voltage, and frequency support. A proposal to offer so called "unbundled" or ancillary services, independent of energy generation, has recently been filed (Western Area Power Administration 1997).

V. ENVIRONMENTAL CONCERNS AT GLEN CANYON DAM

The construction of Glen Canyon Dam is closely associated with the rise of the modern environmental movement in the United States. The announcement of plans for and the eventual construction of the dam spurred a nationwide environmental protest (Martin 1991) which continues to this day (Brower 1997). During the period from 1963 through 1991, Glen Canyon Dam was operated primarily to produce power during on-peak periods while meeting minimum flows during the remaining hours. Operations during this period will henceforth be referred to as "historical operations." These operations caused 7–12-foot fluctuations in the elevation of the river below the dam (Bureau of Reclamation 1994, Appendix D). These fluctuations have been shown to affect the quality of recreation (Bishop et al. 1987), aquatic resources (Maddux et al. 1987) and riparian resources (Stevens et al. 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 opera-

TABLE 1
HISTORICAL AND MLFF OPERATING CRITERION

	Historical Operation Criteria	Modified Low Fluctuating Flow[a]
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
[b]Maximum releases (cfs)	31,500	25,000[c]
Allowable daily flow fluctuations (cfs/24 hours)	Unrestricted	5,000[d] 6,000 or 8,000
Up-Ramp Rates (cfs/hour)	Unrestricted	4,000
Down-Ramp Rates (cfs/hour)	Unrestricted	1,500

[a] Non-operational elements and periodic special releases such as beach-building and habitat-maintenance flows are not included in this table. See Bureau of Reclamation (1995) for details.
[b] Maximums may necessarily be exceeded during high water release years.
[c] Will be exceeded during beach-building and habitat-maintenance flows.
[d] 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.

tions to baseloading of the powerplant, were examined in the final GCDEIS (Bureau of 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. Based largely on Endangered Species Act considerations, the Secretary announced that the facility will be operated according to the Modified Low Fluctuating Flow (MLFF) alternative. 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.

The MLFF operating criteria shown in Table 1 were designed to reduce fluctuations in river elevation to a range of from 1–3 feet (Bureau of Reclamation 1994, Appendix D). 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. 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" (Bureau of Reclamation 1995, 34). Wieringa and Morton (1996) provide some perspective on adaptive management in the Grand Canyon.

VI. RELATED STUDIES

A number of economic analyses of proposed changes in the operation of Glen Canyon Dam have been undertaken (Environmental Defense Fund 1990, 1991; Bishop et al. 1987; Douglas and Harpman 1995; Harpman, Welsh, and Bishop 1995; Power Resources Committee 1993, 1995; Western Area Power Administration 1989a, 1996; Welsh et al. 1995). Only one of these studies contains an estimate of the power system impacts of MLFF. The Power Resources Committee (PRC) estimated the long-run cost of several alternative operating regimes at Glen Canyon using a production expansion model (PRC 1995). Using regression analysis to interpolate between modeled alternatives, the PRC (1995) estimated that the annualized economic cost of changing from historical operations to MLFF was $36.1 million (annualized value, 1996 dollars) per year. Due to excess capacity in the system, the bulk of these costs were projected to be incurred late in the 50-year analysis period. Assessments of the PRC study can be found in National

Academy of Sciences (1996) and General Accounting Office (1996c).

VII. THE ROLE OF SHORT-RUN ANALYSES

Short-run economic analyses, in which the installed base of generation resources (capital) is fixed, are likely to play an important role in future decisions about operations at Glen Canyon Dam (National Academy of Sciences 1996). There are two primary reasons for this: adaptive management and the evolving nature of electricity markets.

Under adaptive management, various changes in the operation of Glen Canyon Dam are now being considered and, in some cases, implemented. For example, under the auspices of the adaptive management program, a two-day, 31,000 cfs high flow was carried out in October 1997 to maintain sediment deposits. A higher flow of longer duration was planned for summer 1997. Other operational changes, such as low steady summer flows for endangered fish research are also contemplated (Bureau of Reclamation 1995). A program of biological and physical research is now ongoing which is likely to lead to additional change. The fluid nature of MLFF operations suggest that short-run economic analyses are an appropriate use of resources.

The dynamic nature of electricity markets and institutions also suggest a short-run analysis approach. Since the Power Resources Committee study was completed in 1995, there have been rapid changes in power markets brought about by FERC orders 888 and 889 (Federal Energy Regulatory Commission 1995) and the move towards competition. Additionally, hydrologic conditions, operational changes at upstream facilities, fuel escalation rates and load growth rates have diverged markedly from those assumed. As a result, the usefulness of this long-run study for decision making is highly questionable.

VIII. ANALYSIS APPROACH

Glen Canyon Dam furnishes less than 3% of the net summer capacity in the six-state interconnected region where CRSP power is sold. The remaining load is met by a mix of thermal, nuclear, co-generation, other hydropower, and renewable generation resources in the region. In this analysis it is assumed the agent operating Glen Canyon Dam is a price taker and operates the dam to maximize societal benefit. In fact, institutions governing the sale of federal power, which are described in Western Area Power Administration (1989b, 1996) and Harpman (1997), vary substantially from this ideal (General Accounting Office 1996a, 1996b).

The process used for estimating economic impacts is shown schematically in Figure 1. Using regional hourly load data, monthly hydrology data, and the appropriate constraint set for the case being examined, the peakshaving model is used to determine the optimal hourly pattern of release and generation for each month in the water year. Next, using

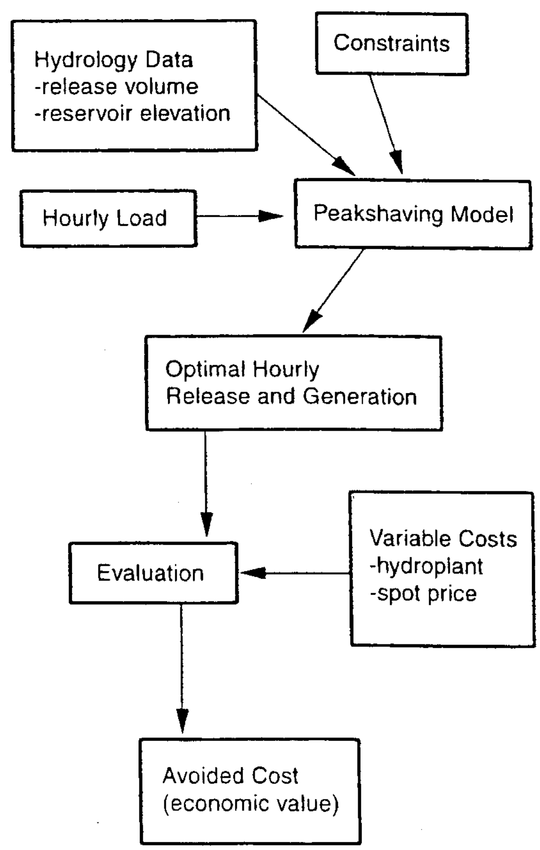

FIGURE 1
Logical Approach Used in This Analysis

the variable cost of operating Glen Canyon Dam and spot market price data, the avoided cost or economic value of the simulated pattern of generation is evaluated for each hour in the water year. This procedure is carried out for both historical and MLFF operation cases. Finally, the hour-by-hour difference in economic value between the two cases is computed.

The Model

As detailed in Wood and Wollenberg (1996), given knowledge about existing generation resources, expected load, the amount of water available for release, regulatory constraints, and engineering limitations, the hydropower producer attempts to generate as much power as possible when it is most valuable. Hourly releases from the dam, q_h, are the variable under management control.

In total, MLFF constraints are unique and outside the capability of most existing models. The peakshaving algorithm (Staschus, Bell, and Cashman 1990), which is also used in several commercial power system models, for example, PROSYM (The Simulation Group 1995) and ELFIN (Environmental Defense Fund 1996), allows for the efficient formulation and solution of this specialized problem. The model employed in this application uses the peakshaving algorithm to reduce peaks in the aggregate load curve, subject to operational and environmental constraints, by optimally releasing water for hydropower generation. This model allows for varying reservoir elevations and represents, in detail, the physical and engineering features of the Glen Canyon Dam and powerplant.

Three functions are used to formulate the model. The first function, $fe[q_h, ele_h]$ calculates the electric energy produced in hour h, by an hourly release, q, at a given reservoir elevation, ele. Both release and energy output are assumed to be constant over any given hourly time step. This function is specified in Appendix 1. The second function, $ef[\cdot]$, is used to calculate the release, q_h, required to produce a given amount of electrical energy at a given reservoir elevation. This relationship is obtained by solving the equation shown in Appendix 1 for release, q_h. The third function, $fv[\cdot]$, converts a release q, measured in cfs and maintained for a one hour period to an equivalent water volume measured in acre-feet (af). It is given by $fv[q] = q * 0.0826$.

The function describing the optimal series of hourly releases, $q_h(x)$, $\forall_h \in \{1, 2, 3, \ldots H\}$, 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, and x is an arbitrary level of release.

$$q_h(x) = \begin{Bmatrix} minf_h, & \text{if } ef[L_h] \leq x \\ ef[L_h] - x, & \text{if } x \leq ef[L_h] \leq x + c \\ c, & \text{if } ef[L_h] \geq x + c \end{Bmatrix} \quad [1]$$

The peakshaving algorithm uses an iterative binary search routine to find an x which uniquely satisfies equation [2], subject to the set of constraint equations [3] through [8]:

$$\sum_{h=1}^{H} fv[q_h(x)] = mvol \quad [2]$$

st:

$$q_h(x) - q_{h+1}(x) \leq uprate \quad [3]$$

$$q_{h+1}(x) - q_h(x) \leq downrate \quad [4]$$

$$q_h(x) \geq minf_h \quad [5]$$

$$q_h(x) \leq c \quad [6]$$

$$c = \min(maxfc, pflow) \quad [7]$$

$$\max(q_h(x) \ldots q_{h+k}(x)) - \min(q_h(x) \ldots q_{h+k}(x)) \leq mdc \quad [8]$$

where:

H = the number of hours in the month
h = the hour during the month
q_h = generation release (cfs) at hour h.
L_h = expected aggregate load (mw) in 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/hr).
$downrate$ = down ramp rate (cfs/hr).
mdc = maximum daily change constraint for the alternative (cfs/24 hrs).
$mvol$ = volume of water available for release during the month (af).
$pflow$ = the maximum flow which can be passed through the generators at a given lake elevation (cfs).
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. Under MLFF, the minimum flow constraint varies by time of day and is described by equation [5]. 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. Equation [8] is the maximum daily change constraint. For MLFF, this constraint varies with the amount of water released during the month. 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 historical and MLFF operations and are not binding except under unusual circumstances.

IX. 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 (Bureau of Reclamation 1994, Appendix B). For clarity of exposition, this analysis is based on a representative water year with an annual release of 11.3 million acre feet (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	3,685.4
November	900,000	3,683.7
December	950,000	3,681.6
January	1,100,000	3,677.7
February	950,000	3,674.8
March	850,000	3,673.2
April	825,000	3,673.8
May	875,000	3,681.2
June	1,000,000	3,690.5
July	1,050,000	3,691.6
August	1,100,000	3,688.4
September	850,000	3,686.3
TOTAL	11,300,000	

Aggregate Load Data

In this analysis, an aggregate hourly load curve was assumed to represent demand during water year 1996. This aggregate load curve was constructed from actual 1996 hourly load data reported by utilities in the Northwest, Rocky Mountain, and Southwest Power Pools. These publicly available data were obtained from information provided to the Federal Energy Regulatory Commission on form 714. These data represent utilities which receive approximately 95% of the electricity generated at Glen Canyon Dam.

Hydropower Production Cost

The variable cost of hydropower production at Glen Canyon Dam was obtained from a recent study which compared a variety of performance benchmarks at private and federal hydropower plants. Although there is no fuel consumed to produce hydroelectricity, hydropower production does result in mechanical wear on generating equipment and requires labor and other inputs. These variable costs of production vary with output level, plant design, size and number of units, and other factors. In a recently released study, the average production or variable cost of producing hydropower at Glen Canyon in fiscal year 1995 was estimated to be \$1.80 / MWhr. This is slightly less than the average production cost for conventional investor-owned hydropower plants of comparable size (National Performance Review Power Management Laboratory 1997).

Spot Market Price Data

In the spot market, electricity is bought and sold hourly on a real-time basis. In the past, these transactions were primarily carried out in private and obtaining detailed site specific market price data for analysis purposes was extremely problematic. This was particularly unfortunate because spot market prices, at least in principle, reflect the marginal cost of producing the next megawatt of electricity. Following the issuance of Federal Energy Regulator Commission (FERC) orders 888 and 889 in 1995 (Federal Energy Regulatory Commission 1995), detailed, site specific, spot market prices for electricity have become available.

Mean daily on-peak and off-peak spot market (non-firm) prices were used to value the simulated generation for this analysis. These data are specific to the Palo Verde, Arizona, and Westwing, Arizona, interchange. This location is a transaction accounting point for electric energy which is ultimately used elsewhere in the southwest. The price data for October 1995 through December 1995 were obtained from Economic Insight, Inc. The data for January 1996 through September 1996 were furnished for this analysis by the Dow Jones and Company, Inc., Energy Service. 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 Harpman (1997, Appendix 2).

The spot market price data used for this analysis reflect current conditions in the regional power market As of the date of this analysis (mid-1997), the electricity market in the region where CRSP power is sold is characterized by the presence of substantial amounts of surplus generation capacity. This regional surplus is the result of past optimistic assessments of load growth, open access to transmission lines enabled by FERC orders 888 and 889, and advances in technology, particularly in gas turbine peaking power units (Energy Information Administration 1996a).

X. RESULTS

Using the approach described in Figure 1, the constrained peakshaving model was used to simulate the operation of Glen Canyon Dam under both the historical operating criteria and MLFF for all months during the representative water year. Figure 2 illustrates the results of this simulation for one week in March 1996. As shown in this figure, under MLFF 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.

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 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% to 1,032 and 1,020 MW, respectively.[1] For this simulation, the capacity reduction results

[1] These capacity effects are for a representative water year. 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 Area Power Administration (1989b).

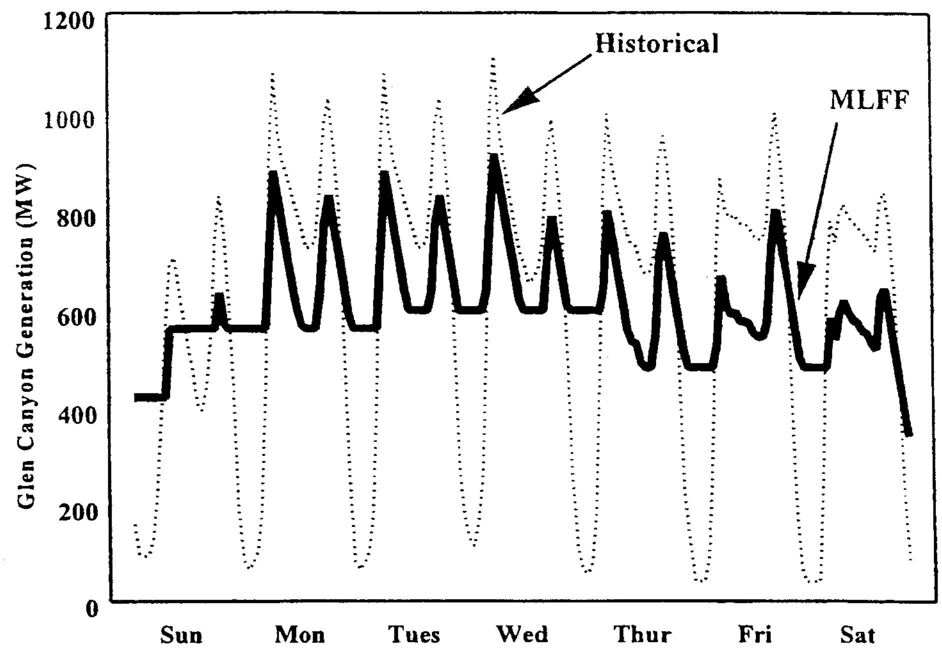

FIGURE 2
SIMULATED HOURLY GENERATION UNDER HISTORICAL AND MLFF OPERATION CRITERIA

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.

MLFF limits both the capacity of the hydropower plant and its ability to change output levels. As a result, the Glen Canyon hydropower plant is less responsive to changes in load. Relative to historical operations, this reduces the level of ancillary services such as regulation, reserves, voltage and frequency support, which this facility can provide. To the extent that these services are valued independently of generation in the future, this may diminish the economic value of this hydropower facility.

In addition to routine operations, MLFF constraints could potentially reduce the ability of Glen Canyon to respond to system emergencies, such as the failure of thermal units or transmission lines. This could affect the reliability of the interconnected power system. In recognition of this possibility, MLFF contains provisions which allow the constraints to be exceeded during power system emergencies.

Using the variable cost of production at Glen Canyon Dam and spot market prices, the economic value or avoided cost of this simulated hydroelectric generation was calculated. Monthly estimates of economic value are shown in Table 3. As shown in this table, shifting generation from on-peak to off-peak periods reduces the economic value of the hydroelectricity generated by \$6,173,000 for this representative water year. This amounts to a reduction of 8.8%.

XI. LIMITATIONS

The short-run estimates of economic value presented here are sensitive to the quantity and pattern of water release across the year, the reservoir elevations used, and conditions in the electric power market which are reflected by spot market prices. 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 discre-

TABLE 3
SIMULATED HISTORICAL AND MLFF ECONOMIC VALUE, BY MONTH

	Historical ($)	MLFF ($)	Difference ($)
October	5,214,000.00	4,833,000.00	(381,000.00)
November	5,401,000.00	4,992,000.00	(409,000.00)
December	4,610,000.00	4,173,000.00	(437,000.00)
January	6,613,000.00	6,039,000.00	(574,000.00)
February	4,748,000.00	4,367,000.00	(381,000.00)
March	3,778,000.00	3,588,000.00	(190,000.00)
April	4,400,000.00	3,956,000.00	(444,000.00)
May	4,405,000.00	3,848,000.00	(556,000.00)
June	5,668,000.00	5,134,000.00	(534,000.00)
July	8,627,000.00	7,728,000.00	(899,000.00)
August	10,563,000.00	9,677,000.00	(886,000.00)
September	6,149,000.00	5,666,000.00	(483,000.00)
TOTAL	70,174,000.00	64,001,000.00	(6,173,000.00)

tionary manner is limited. However, to the extent that operational flexibility exists, these units could be used to partially offset the power system impacts of changes in operations at Glen Canyon Dam. Finally, this analysis is restricted to direct power system impacts. Although releases from Glen Canyon Dam have been shown to affect economic use value (Bishop et al. 1987), total economic value (Welsh et al. 1995) and emissions in the region (Bureau of Reclamation 1995, Power Resources Committee 1995), these topics are not addressed here.

XII. CONCLUSION

This paper describes a general framework for estimating the short-run economic costs of introducing a particular set of hourly constraints on hydropower operations at Glen Canyon Dam. Using this framework, the short-run economic value of hydropower is estimated to fall 8.8% annually when Modified Low Fluctuating Flow constraints are imposed. The approach described is suitable for estimating the short-run change in the economic value of electric energy produced from a hydropower facility under a wide range of hourly constraints. Moreover, it employs market-based prices, is far less costly to implement than comparable frameworks, and can be useful in a broader analysis of hydropower constraints. 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 and policy decision making.

APPENDIX
RELEASE, HEAD, AND GENERATION

The electric energy generated at Glen Canyon Dam is a function of discharge through the turbines and reservoir elevation as shown in the equation below (units of measure shown in parentheses). Both discharge and electrical energy production are assumed to be constant over any given hourly time step.

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

where:

h	= hour
Γ	= 62.40, The specific weight of water at 50° Fahrenheit (lbs/ft^3).
eff	= 0.889 efficiency factor (dimensionless).
$head(\cdot)$	= effective head (feet).
q_h	= turbine discharge (cfs).
ele_h	= reservoir elevation (feet above mean sea level)

hptokw = 737.5, Horsepower to kilowatt conversion factor (kw/(ft-lbs/sec)). Note: There are 1000 kilowatts in a megawatt.

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

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