Estimates of Power System Impacts of Proposed Interim Flow Release Patterns at Glen Canyon Dam

for the

U.S. Bureau of Reclamation

Department of the Interior

Environmental Defense Fund
Oakland, California
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Executive Summary

The Secretary of Interior is considering implementation of flow release constraints at Glen Canyon Dam on an interim basis, pending completion of the Environmental Impact Statement assessing the effect of current operations and alternatives on the Grand Canyon. This study uses a computer-based simulation model to examine the net economic impacts of changes in power system operations resulting from a set of alternative release requirement scenarios over a period beginning in October 1991 and ending in September 1995. In addition, emissions impacts of the changes are also examined.

Flow release constraints at Glen Canyon Dam do not change the overall amount of electric energy that can be generated; instead, this energy is generated at different times. There is an economic cost because there is a loss in the operating flexibility of the hydroelectric generating plant.

Four alternative flow release requirement scenarios were examined. They are presented in order of least to greatest in both magnitude of change and cost of change to users of electricity. In order, the four scenarios are those proposed by the Western Area Power Administration (Western), the Bureau of Reclamation (USBR), the Glen Canyon Environmental Studies Research/Scientific Team (GCES), and the Ecological/Resource Managers (E/RM).

The proposed scenarios, as well as the results, are explained in detail in the main body of the report. Basically, Western's proposal advocates little change in operations, including no change to maximum flow, at an estimated cost of $1.1 million in 1992 compared to current operations. USBR proposes greater restrictions in operations, including limiting maximum flow to no more than 22,000 cubic feet per second (cfs), at a cost estimated to be $8.5 million in 1992. The GCES team proposes yet greater restrictions, especially in limiting fluctuations in flow on both an hourly and a daily basis. The estimated cost for their scenario is $9.3 million in 1992. Finally, the cost of the E/RM proposal, which differs from the GCES proposal only in an increased minimum flow, is $9.4 million in 1992. Estimated costs for all scenarios increase in the years beyond 1992.

These costs are a very small percentage -- significantly less than 1% -- of overall power system costs, even when allocated entirely to the utilities which currently receive Glen Canyon power.

All costs estimated in this study are those incurred by supplementing loss of operating flexibility at Glen Canyon Dam with less efficient operation of fossil fuel-fired power plants. Thus, the estimated costs are net economic impacts across all utilities rather than from the perspective of any limited group of utilities. The text of the report includes a discussion of differences between the methodology used in this "economic" study and that which has been used in Western's "financial" analyses.

The power from Glen Canyon Dam is sold to preferential customers at below market rates. Assuming that all costs are incurred by these preferential customers, any rate increase would still leave the rate at well below market level. Therefore, the power would still be sold, there would be no impact on the U.S. Treasury, and the preferential customers would still be getting a bargain.

Improvements in energy efficiency (often called "demand-side management"), the preferred least-cost new resource option for many electric utilities today, were not considered in this study due to the short length of the study period. They should be given full consideration in the power studies portion of the EIS.

Emissions impacts are even smaller, and in several cases positive. The change in operations slightly increases sulfur dioxide emissions, while nitrogen oxide and carbon dioxide emissions generally decrease.

Estimates of Power System Impacts

of Proposed Interim

Flow Release Patterns

at Glen Canyon Dam[1]

I. Introduction

The United States Department of the Interior is currently preparing an Environmental Impact Statement to assess flow release patterns and proposed changes in release requirements at Glen Canyon dam. Since current operations -- which are largely geared toward optimizing power production -- are causing environmental damage within the Grand Canyon, agencies of the United States government have proposed imposing various release requirements on an interim basis, pending completion of the Environmental Impact Statement. Such interim requirements would restrict the extent to which releases would be optimized only for power production purposes, and thus could be expected to increase the economic costs of meeting power demands in the Southwest region. This study uses a computer-based utility system simulation model to forecast the magnitude of potential cost increases under several different flow release requirement scenarios.

In addition, the effects of the different release requirements on powerplant emissions of sulfur oxides, nitrogen oxides, and carbon dioxide are also forecast during the interim period 1992 through 1995.

The alternative flow release scenarios examined in this study can be compared to current operations at Glen Canyon dam. Current operations allow water to be released from the dam at a maximum rate of 31,500 cubic feet per second (cfs) for power generation purposes. (This rate can be exceeded if flood control needs require it.) The release rate must be at least 1,000 cfs in winter (October through March) and at least 3,000 cfs in summer (April through September). There is no restriction on how fast releases can be changed from hour to hour (the "ramp rate").

The alternative flow release scenarios illustrate the range of impacts that may occur as a result of interim flow release requirements at Glen Canyon dam. A total of four different alternative release scenarios have been examined, each supported by at least one governmental agency. They are described below in order of least to greatest change from current operating criteria. The proposed criteria are also summarized in table 1.

The first alternative release scenario, as proposed by the Western Area Power Administration (Western), would require an increased minimum flow of at

[1] The methodology for this study and the text for this report are very similar to those used in EDF's earlier report, Estimates of Economic Impacts of Implementing Interim Flow Release Patterns at Glen Canyon Dam, Environmental Defense Fund, July 12, 1990, which was prepared at the request of the U.S. House of Representatives, Committee on Interior and Insular Affairs, Subcommittee on Water, Power and Offshore Energy Resources.

TABLE 1

GLEN CANYON DAM INTERIM OPERATIONS

SUMMARY OF OPERATING CRITERIA RECOMMENDATIONS

June 25, 1991

Parameter	Historical	R/S Group	E/RM Group	USBR Option	WAPA
Max. Release (cfs)	31,500	20,000	20,000	20,000(1)(2) 22,000(3)	31,500
Min. Release (cfs)	3,000/1000	5,000	8,000	5,000(4)	3,000/ 5,000
Ramp Rates cfs/hr.				4 hour/1 hour	
Up	No Limit	2,000	2,000	8,000/4,000(4)	No Limit
Down	No Limit	1,000	1,000	4,800/2,000(1) 8,000/2,500(2) (3)	4,000/ 5,000
Daily Change (cfs)	30,500	5,000	5,000	8,000(1) 11,000(2) 15,000(3)	No Limit
Flooding	1 in 20 yrs.	Minimize	Minimize	Minimize	Minimize

R/S Group = Research /Scientific Group - Recommendations For Interim Operating Procedures For Glen Canyon Dam - April 10, 1991

E/RM Group = Ecological/Resource Managers - Letter Report - Review of Interim Flow Recommendations - March 29, 1991

USBR = Bureau of Reclamation (Committee of Five) - Presented at Cooperating Agencies meeting on June 13-14, 1991, including a phased approach which was dropped from consideration

WAPA = Western Area Power Administration - Letter and Concept of Interim Operating Criteria - May 22, 1991 - Comments on the WAPA concept was submitted by the Colorado River Energy Distribution Association and the Upper Colorado River Commission on May 29, 1991.

Notes:
(1) Low monthly volume - less than 600,000 acre-feet
(2) Medium monthly volume - 600,000 to 800,000 acre-feet
(3) High monthly volume - over 800,000 acre-feet
(4) All months

least 3000 cubic feet per second (cfs), and a maximum hourly decrease in flow of at most 5000 cfs/hour. Western proposes modifying these parameters a if "favorable market conditions exist", but the computer modeling was done assuming the former less restrictive parameters for dam operations. The maximum rate of 31,500 cfs would be retained.

The second alternative release scenario, as proposed by the Bureau of Reclamation (USBR) would require a minimum release rate of 5,000 cfs year round. The maximum release rate would be restricted between 20,000 cfs and 22,000 cfs, depending on monthly volume. Restrictions on fluctuations would be imposed each hour, every four hours and each day, again depending on monthly volume. The daily change would be limited to 8,000 cfs in low volume months, 11,000 cfs in medium volume months, and 15,000 in high volume months. Over any four hour period, an increase in flow would be limited to 8,000 cfs in all months, and a decrease would be limited to 4,800 cfs in low volume months and 8,000 cfs in medium and high volume months. Over any one hour period, an increase would be limited to 4,000 in all months, and a decrease would be limited to 4,800 in low volume months and 8,000 in medium and high volume months.

A third alternative, proposed by the Glen Canyon Environmental Studies Research/Scientific Group (GCES) would require a minimum release rate of 5,000 cfs and a maximum release rate of 20,000 cfs. The daily change would be limited to 5,000 cfs. Over any one hour period, increases would be limited to 2,000 cfs and decrease limited to 1,000 cfs. In addition, the average flow for any day must be at least 8,000 cfs.

A fourth alternative, proposed by Ecological/Resource Managers (E/RM), a group that includes the National Park Service, United States Fish and Wildlife, Arizona Game and Fish, as well as Native American groups, is the same as the GCES proposal, but would require a minimum release rate of 8,000 cfs.

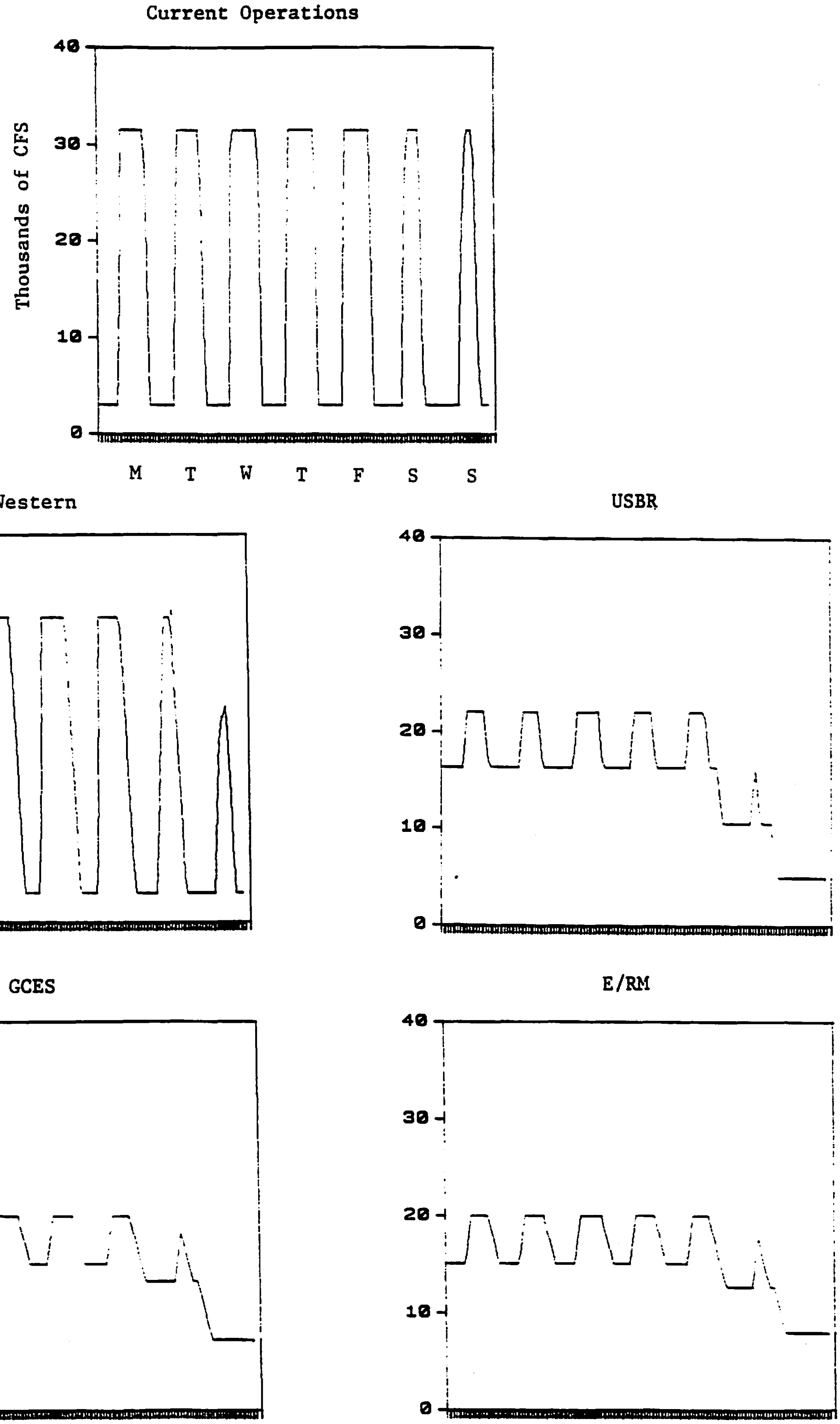
How do these different release requirements affect power generation costs? Electric generation is most valuable at peak-load times (such as summer afternoons when air-conditioning requirements are greatest) because electric utilities typically have to call upon higher-cost generation resources to meet these higher loads. In a typical month water supply will not be great enough to allow a 31,500 cfs release rate around the clock. Instead, the value of water for power generation can be maximized by releasing the limited amount of water preferentially at peak-load times, and as little as possible at other times. The current operations release requirements allow a great deal of flexibility to do this. The resulting fluctuating flows are the subject of the current environmental investigations.

Under all proposed alternatives, operations at Glen Canyon Dam would be more restricted. While there is no difference in the total amount of water released from the dam in a month, and thus no difference in the total amount of energy generated, less of that total is available to be scheduled at peak-load times. Thus all alternatives shift some energy generation from peak load times to non-peak-load times. Other, higher-cost coal and natural gas resources must be turned on at peak load times, thus increasing costs. The additional hydroelectric generation at non-peak times means that fossil-fuel plants will generate less at these times, thereby saving money. Since the cost of fossil-fuel generation is less at off-peak times than on-peak times, the off-peak savings will not be as great as the on-peak costs.

Figure 1 shows an example of how the Elfin model simulated the operation of Glen Canyon Dam for the current operations case and each of the four alternative scenarios. In each case, the model used the available water for each month, subject to the appropriate operating restrictions, to serve peak electrical loads as efficiently as possible. The examples in Figure 1 all

Figure 1

Dam Operations - July 1992



represent a week in July 1992. Maximum and minimum flow rates are most obvious, but daily and hourly restrictions can be seen as well. Factors other than the restrictions may affect the simulated operations, e.g. USBR's proposal would have allowed a daily fluctuation of up to 15,000 cfs in the month shown, but the relatively large amount of water available, combined with the four hour restriction, limited the actual daily fluctuation to much less.

II. Study Method

This study calculates the economic effects of changes in the hour-to-hour scheduling of Glen Canyon Dam generation by simulating the operation of the most directly affected electric systems of which the Glen Canyon powerplant is a component. The interconnected western power grid which includes Glen Canyon Dam is a far-flung entity extending through British Columbia. Power from the Colorado River Storage Project (CRSP), a set of dams on the Colorado River, of which Glen Canyon is by far the major component, has regularly been sold as far away as California. This study restricts attention to the power systems most directly affected by changes in Glen Canyon generation. These include customers of Colorado River Storage Project power (municipal and publicly-owned utilities in Arizona, New Mexico, Utah, Colorado, and southern Nevada), and, for those customers which do not have their own generating plants, their alternative suppliers (generally investor-owned utilities in the same region).

The electric system simulation used in this study focuses on the actual economic costs of changing operations. That is, the simulation examines the physical and resource changes involved in burning fuel and generating electricity, rather than financial changes that come with different power transactions. Thus, the increased profit that utility A may be able to make when it increases sales to utility B is <u>not</u> a subject of this study. The cost of the additional fuel that utility A burns to supply utility B is. This study takes a <u>net</u> economic impacts perspective across utilities rather than the perspective of any single utility or limited group of utilities.

A single utility or entity such as the Western Area Power Administration (which markets and distributes Colorado River Storage Project Power) will consider only its own "wins" and "losses" which result from power transactions. These transactions will ordinarily include a mark-up component (which, from an economic perspective, represents a transfer payment rather than a resource cost). "Winners" and "losers" may largely balance out when all such entities are considered. This study considers only the net loss over all such entities; it does not calculate any single entity's position.

There are several aspects of the distribution of the net economic cost that are known, however. Increases in power costs will fall on Colorado River Storage Project firm customers in either of two ways. One possibility is that the firm customers' share of Glen Canyon resources will be changed in accordance with changes in Glen Canyon operations, thereby making the power less valuable and requiring these utilities to generate or purchase make-up power at on-peak times. Alternatively, the Western Area Power Administration could continue to supply power in accord with pre-existing contracts and will itself purchase make-up power. In this case rates to firm customers will increase to cover Western's costs. For these reasons the net cost impacts per kilowatt-hour are most appropriately attributed to those kilowatt-hours delivered to firm customers.

An additional aspect of the distribution of net economic costs that is also known is the effect on the federal treasury. Since Western currently markets Glen Canyon power at a cost well below its free-market value, Western will be able to adjust firm power rates to recover any increases in its costs. Aside from slight differences in the timing of the repayment of Western's costs there is no effect on Western's payments to the federal treasury.

The simulation of the power systems is performed through the use of the Elfin computer model. The Elfin electric utility simulation model was developed by the Environmental Defense Fund, and is currently widely used in California and elsewhere in the country. Some of the users and uses of the Elfin model are summarized in Appendix 1. In this study the Elfin model simulates the operation of more than one hundred generating units in the Southwest region.

III. Comparison with Western's Methodology

The Western Area Power Administration is the federal agency responsible with marketing the power from Glen Canyon, and other dams. They have more than 100 customer with contracts for firm power. Most of these customers are small utilities without sources of generation who purchase power from larger utilities as well as Western. However, a some of Western's customers are large utilities who do have their own sources of generation.

During many years, Western's firm contracts commit them to supply more energy than they can generate. Western buys fossil-fuel generated power from other utilities for this purpose. The cost of this purchase power is blended into the rate Western charges its firm customers. Currently most of this power is bought at off-peak times. Typically, off-peak power is sold at the cost of production, i.e. fuel costs plus costs of operations and maintenance.

Under the alternatives, Western would have to purchase more power at peak-load times and less at off-peak times. Costs of production at peak times are greater. Moreover, with more demand for power at peak load times, sellers of power may want to charge more than the costs of production, they may try to charge "capacity payments", to recoup some of their investments in their power plants.

The principal estimates in Western's financial analyses are the increased costs of purchased power. These estimates include both the increased costs of production and capacity payments. EDF's estimates of increased costs include only the costs of production, since they represent the only physical change to how the power system is operated .

From an economic perspective, these capacity payments are transfer payments. There is a financial cost to the buyer and a financial benefit to the seller, but no net overall economic impact. If capacity payments are made, the sellers will benefit. Western is not measuring these benefits. The sellers may, in fact, be some of Western's firm customers, as some of them do have excess generating capability. At any rate, according to the federal Principles and Guidelines, decisions should be based on overall net economic impacts rather than impacts to a select group.

Additionally, Western's latest studies have shown considerable uncertainty in the extent to which they would have to make capacity payments to obtain peak-load power.[2] Certainly Western must err on the conservative side to be sure that they can meet firm contracts, but their estimates for capacity payments may be overstated.

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[2] Cooperating Agencies meeting, July 1, 1991, Phoenix AZ. Western was represented by Lloyd Greiner, Ken Maxey, Jeff McCoy and Ken Ackerman.

IV. Results

The Elfin model measures the total costs of producing electricity for the simulated power systems for each year of the study period under each case. These costs include the costs of powerplant fuel and variable operation and maintenance expenses. (These costs do not include fixed costs such as interest, or costs such as administrative and general expenses which are not expected to change as a result of changes in Glen Canyon operations.) Table 2 shows these total production costs for each flow release scenario and year from 1992 through 1995.

In addition, table 2 calculates the change in total production costs in each case compared to the current operations case. Thus, alternative I, Western's proposal, results in increased costs of $1.1 million in 1992 compared to current operations. Similarly, alternatives II, III and IV, representing proposals by USBR, GCES and E/RM result in increased costs of $8.5 million, $9.3 million and $9.4 million in 1992 compared to current operations.

Table 1 also shows the cost increases compared to the base case as a percentage of total costs. In general, the percentage impacts increase over time. This occurs as the result of two factors: first, power system loads are forecast to increase approximately 3% per year during this period; and second, Glen Canyon hydroelectric generation is also forecast to increase, since reservoirs are currently low and water supplies are expected to increase under expected average hydrologic conditions. The first factor makes hydroelectric generation relatively more valuable over time, since increasing loads means that higher-cost thermal resources must be used to meet these loads. The second factor means that Glen Canyon hydroelectric generation is a larger share of the generation "mix," and any constraint on the operational flexibility of this resource will have a greater relative impact.

Finally, the last section of table 2 shows the impact of the cost increases on Colorado River Storage Project firm customers. These impacts are calculated on a cost per kilowatt-hour basis. For example, alternative I would increase costs to CRSP firm customers by 0.02 cents per kilowatt-hour in 1992. Since the rates for CRSP firm power average approximately 1.5 cent per kilowatt-hour currently, this represents an approximately 3% increase in the cost of CRSP power. These figures overstate the cost impact of the changes, however. The cost of CRSP power represents on average only a small fraction of the total costs of the utilities which receive this power. These utilities generate or purchase the balance of their power requirements from other sources, and in addition have interest costs, distribution system costs, operation and maintenance costs, and so forth. Thus, the increase in rates to the residential and business customers of these utilities is small indeed; on average less than 0.3% in this case.

Figure 2 charts the change in total costs for each case compared to current operations by year.

Tables 3 through 5 show powerplant emissions results under each case. Table 3 shows sulfur dioxide emissions, table 4 shows nitrogen oxide emissions, and table 5 shows carbon dioxide emissions. Sulfur dioxide emissions increase in most of the alternative cases, while in most cases nitrogen oxide emissions decrease. Carbon dioxide emissions decrease in most of the alternative cases. The decreases in carbon dioxide emissions occur because of shifts from coal-fired generation (which emits proportionately more carbon dioxide) to natural gas-fired generation. Carbon dioxide emission rates per Btu of fuel do not vary significantly among coal plants, nor do they vary among natural gas plants. On the other hand, sulfur dioxide emission rates vary from coal plant to coal plant depending on the sulfur content of the coal fuel. These increases would be relatively easy and inexpensive to

Table 2

Total Production Costs by Flow Release Pattern and Water Year *

Total Costs (million $)

	1992	1993	1994	1995
Current Operations	1794.2	1946.8	2105.7	2301.9
Alternatives:				
I - Western Proposal	1795.3	1948.2	2107.4	2304.1
II - USBR Proposal	1802.8	1957.7	2119.6	2317.2
III - GCES Proposal	1803.5	1958.6	2120.6	2317.9
IV - E/RM Proposal	1803.6	1958.6	2120.6	2317.9

Change From Current Operations (million $)

I - Western Proposal	1.1	1.4	1.7	2.1
II - USBR Proposal	8.5	10.9	13.9	15.3
III - GCES Proposal	9.3	11.8	15.0	16.0
IV - E/RM Proposal	9.4	11.8	15.0	16.0

Change From Current Operations (percent)

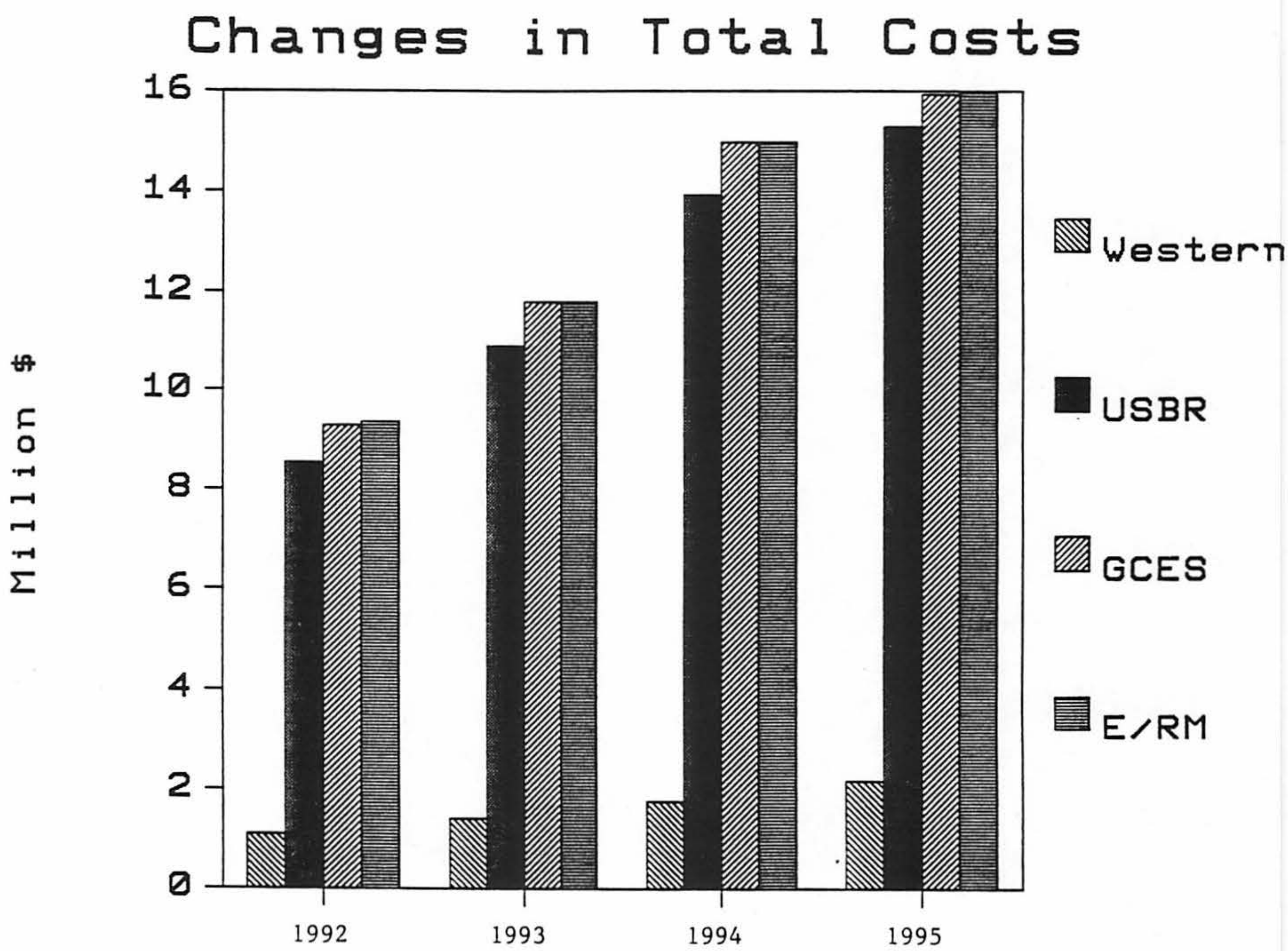
I - Western Proposal	0.06%	0.07%	0.08%	0.09%
II - USBR Proposal	0.48%	0.56%	0.66%	0.66%
III - GCES Proposal	0.52%	0.60%	0.71%	0.69%
IV - E/RM Proposal	0.52%	0.60%	0.71%	0.69%

Cost per kWh of Firm Sales (cents per KWH)

I - Western Proposal	0.02	0.02	0.03	0.04
II - USBR Proposal	0.15	0.19	0.24	0.27
III - GCES Proposal	0.16	0.20	0.26	0.28
IV - E/RM Proposal	0.16	0.20	0.26	0.28

* Water year 1992 equals October 1991 through September 1992

FIGURE 2



Changes in Total Costs
Million $
16
14
12
10
8
6
4
2
0
1992
1993
1994
1995
Western
USBR
GCES
E/RM

Table 3

SO2 Emissions by Flow Pattern and Year

System SO2 (tons)

	1992	1993	1994	1995
Current Operations	261009	266155	273134	281000
I - Western Proposal	261047	266325	273418	281292
II - USBR Proposal	260919	266966	273983	282282
III - GCES Proposal	260879	266811	273968	282265
IV - E/RM Proposal	260894	266819	273972	282264

Change From Current Operations (tons)

	1992	1993	1994	1995
I - Western Proposal	38	170	283	293
II - USBR Proposal	-91	812	849	1282
III - GCES Proposal	-131	657	834	1266
IV - E/RM Proposal	-115	664	837	1264

Change From Current Operations (percent)

	1992	1993	1994	1995
I - Western Proposal	0.01%	0.06%	0.10%	0.10%
II - USBR Proposal	-0.03%	0.30%	0.31%	0.46%
III - GCES Proposal	-0.05%	0.25%	0.30%	0.45%
IV - E/RM Proposal	-0.04%	0.25%	0.31%	0.45%

TABLE 4

NOx Emissions by Flow Pattern and Release Year

System NOx

	1992	1993	1994	1995
Current Operations	342848	348424	356280	363761
I - Western Proposal	342763	348334	356207	363708
II - USBR Proposal	342329	348294	356035	363787
III - GCES Proposal	342282	348289	356048	363967
IV - E/RM Proposal	342279	348291	356053	363971

Cahnges From Current Operations (tons)

	1992	1993	1994	1995
I - Western Proposal	-85	-90	-73	-53
II - USBR Proposal	-519	-130	-245	26
III - GCES Proposal	-566	-135	-232	207
IV - E/RM Proposal	-569	-133	-228	210

Changes From Current Operations (percent)

	1992	1993	1994	1995
I - Western Proposal	-0.02%	-0.03%	-0.02%	-0.01%
II - USBR Proposal	-0.15%	-0.04%	-0.07%	0.01%
III - GCES Proposal	-0.17%	-0.04%	-0.07%	0.06%
IV - E/RM Proposal	-0.17%	-0.04%	-0.06%	0.06%

Table 5

CO2 Emissions by Flow Release Pattern and Year

System CO2 (millions of tons)

	1992	1993	1994	1995
Current Operations	100.48	102.29	104.47	106.71
I - Western Proposal	100.47	102.29	104.47	106.71
II - USBR Proposal	100.41	102.26	104.43	106.73
III - GCES Proposal	100.40	102.26	104.43	106.73
IV - E/RM Proposal	100.40	102.26	104.43	106.73

Changes from Current Operations (millions of tons)

	1992	1993	1994	1995
I - Western Proposal	-0.01	-0.00	-0.00	-0.00
II - USBR Proposal	-0.07	-0.03	-0.04	0.02
III - GCES Proposal	-0.08	-0.03	-0.04	0.02
IV - E/RM Proposal	-0.08	-0.03	-0.04	0.02

Changes From Current Operations (percent)

	1992	1993	1994	1995
I - Western Proposal	-0.01%	-0.00%	-0.00%	-0.00%
II - USBR Proposal	-0.07%	-0.03%	-0.04%	0.02%
III - GCES Proposal	-0.08%	-0.03%	-0.04%	0.02%
IV - E/RM Proposal	-0.08%	-0.03%	-0.04%	0.02%

mitigate by including emissions factors in the optimization criteria used to operate the power system.

IV. Conclusion

Changes in flow release patterns at Glen Canyon dam which restrict the degree to which these flow releases can be optimized purely for power generation purposes do increase power system generating costs in the southwest region. More restrictive flow release patterns cause greater increases in cost. The cost increases range from $1.1 million dollars in 1992 under Western's proposal to a maximum of $9.4 million dollars under the E/RM proposal.

very small %/in comparison with total value of production

No operating flexibility was considered in this study. The simulation did not allow maximum release rates to be exceeded for emergency purposes. There are other methods of increasing operating flexibility which should be considered for both power generation and environmental goals. For example, monthly water releases are determined by the Bureau of Reclamation considering goals primarily for water delivery and flood control. To the extent there is remaining flexibility in month-to-month water releases these will be scheduled to optimize power generation. With changes in daily flow release patterns these month-to-month schedules could be re-optimized. Such re-optimization, which could further reduce the costs of changing flow release patterns, was not examined in this study.

An additional method of ameliorating cost impacts was also not considered in this study: energy efficiency improvements. Given the low price of Colorado River Storage Project power, utility customers have had relatively little incentive to promote energy conservation and load management among their residential and business consumers. Current research points to significant remaining potentials for energy efficiency improvements among electricity users at costs below the costs of thermal generation. Load management, by cutting peak-period electric demands, has the potential to directly mitigate the effects of restricting peak-period generation at Glen Canyon dam. Potential cost savings from increased energy efficiency would quickly outweigh the cost increases due to changing flow release patterns at Glen Canyon dam.

Appendix 1

Study Method

A. Power Systems Simulation

1. The Elfin Model

The method used in this study to calculate the economic costs of changing operations at Glen Canyon dam is to simulate changes in Glen Canyon electric generation within the context of the power systems most directly affected by those changes. Since these power systems involve more than a hundred electric generating units in portions of seven states, and since power system operations are extremely complex, a computer-based model is necessary for this task.

The "Elfin" electric utility production cost simulation model is used in this study. The Elfin model was developed by the Environmental Defense Fund. The model is currently the primary analysis tool used by the staffs of both the California Public Utilities Commission and the California Energy Commission. The Southern California Edison Company uses Elfin as its primary tool for long-range planning. In addition, Elfin is used by a number of consulting and engineering firms in California and elsewhere.

The Elfin model is used by these organizations for a variety of purposes related to the operation of electric generation systems. For example, before the California Public Utilities Commission Elfin is used to make short-term (one year) forecasts of fuel use and marginal energy costs for purposes of setting electric rates and "Qualifying Facility" (cogeneration and independent power producer) purchase prices. The model is also used by both of the California regulatory commissions and others to do long-term planning. For example, the model is used to determine what new plants would be most cost effective. It is also used to determine what levels of conservation and demand-side management would be most cost effective.

In addition, the Elfin model has been recommended for use, along with the Electric Power Research Institute's EGEAS model, in the Department of Interior's Environmental Impact Statement process currently under way for Glen Canyon operations. The Glen Canyon Environmental Studies' Power Economics Team, of which the Environmental Defense Fund is a participating member, conducted "prototype" studies to determine acceptable methods for calculating the economic impacts of changes in operations at Glen Canyon dam. Three different methods were compared: the Western Area Power Administration's "Alternative Thermal Plant" method; the EGEAS model; and the Elfin model. The prototype studies using each of these methods were conducted by Western Area Power Administration, Stone & Webster Management Associates, and the Environmental Defense Fund, respectively. The Alternative Thermal Plant method was judged to be less useful than either of the models because only the models could take into account the complexity and range of impacts involved in the power system. The EGEAS model was favored because of its ability to make "optimum generation expansion decisions" in the long run, when new generating capacity may be necessary to replace lost peaking capacity from Glen Canyon (since there is currently significant excess capacity in the southwest region the issue of new generating capacity is not particularly relevant to interim operating conditions at Glen Canyon). The Elfin model was recommended as a valuable cross-check for EGEAS results.

2. What the Elfin Model Does

The Elfin electric utility production simulation model simulates the production of electricity by generating units to meet customer demands. The Elfin model begins with the "load shape" -- the hour-by-hour demand for electricity. The model then uses data on the electric generating plants available to meet load to simulate how these plants will be operated. Data such as the capacity of each plant, the type and cost of fuel each plant uses (or the availability of water for hydroelectric generation), the efficiency of each plant, and the maintenance requirements and reliability of each plant are used in the simulation. The simulation is "probabilistic;" an important factor in the operation of electric systems is the outages of generating units due to mechanical breakdowns. Since such outages cannot be forecast except on an average, expected basis, the model weighs the probability of each combination of outage events in calculating its results.

The model simulates the operation of electric systems with essentially the same goal as power system operators: to meet electric needs at minimum cost subject to constraints on reliability, operating flexibility, and other factors. The Elfin model includes a "commitment" algorithm and a "spinning reserve" algorithm. The commitment algorithm decides when slow-start plants must be committed for reliability purposes (that is, when each slow-start plant must be started up, with the constraint that in order to be available for peak-period loads, such plants must remain running at a minimum level during non-peak times). The spinning reserve algorithm decides when quick-start units (such as combustion turbines), which would otherwise not be economic, must be brought on-line to meet operating reserve requirements.

B. System Definition for the Elfin Simulations

In this study, the Elfin model simulates operations on a month-by-month basis, with each month represented by a "typical week" within that month.

This monthly simulation is conducted for power systems covering portions of seven states. The Colorado River Storage Project (CRSP), of which Glen Canyon dam is the major component, has over one-hundred customers for firm electric power, mostly in Arizona, New Mexico, Utah, Colorado and southern Nevada. Most of these customers are small utilities which have no generating resources of their own, but purchase power from larger neighboring utilities when they have needs in excess of their firm contract power. Consequently all major utilities and thermal generating units in these states are potentially affected by a change in operations at Glen Canyon. (Interconnected utilities also own plants or portions of plants in Wyoming and Texas.)

The simulated system consists of 70 coal-fired units, 3 nuclear generating units, 58 oil- or gas-fired steam turbines or combined-cycle units, a large number of combustion turbines, all CRSP units (including, of course, Glen Canyon), most of the non-federally owned hydro projects in the region and two pumped-storage plants.

All of these systems are modelled as an interconnected, bulk system in the Elfin simulations for this study. While significant portions of the system are subject to a formal power pooling agreement that coordinates reserve capacity sharing and economy energy transactions, there are still significant transmission constraints and coordination constraints within the larger interconnected area. The transmission and coordination constraints have been approximated within this study's Elfin simulations by insuring that certain minimum levels of local generation would occur in each sub-area. This is accomplished by making plants in each sub-area "must-run" plants, which must be committed for local generation and reliability purposes regardless of economics.

The bulk-system simulation used in this study is not as sophisticated as the approach recommended for the Environmental Impact Statement by the Power Economics Team. The recommended approach is to model a number of utilities which receive Glen Canyon power on a utility-by-utility basis, taking specific account of their interconnections with neighboring utilities. This detailed approach is deemed necessary in order to measure utility-specific impacts of both changes in Glen Canyon generation and changes in Colorado River Storage Project firm contracts. Neither sufficiently detailed data nor time were available for such a detailed approach in this study; since neither utility-specific impacts nor changes in firm contracts are of interest in this study, such a detailed approach was deemed unnecessary.

The Western Area Power Administration (Western) is in charge of marketing and distributing CRSP power. Since actual energy and capacity available from CRSP generating units varies from year-to-year with hydrological conditions, and this energy and capacity may be greater or less than Western's firm contract obligations, Western also conducts transactions in order to meet its firm contract obligations, or to sell surpluses above the firm contract amounts. The Elfin simulations do not separate these transactions in any special way. Instead, such transactions are modelled concurrently with other system power flows.

C. Notes on Data and Sources

As described above, the Elfin production cost model dispatches generating resources subject to operating constraints in order to serve customer load as economically as possible. Thus, both loads and resources must be specified in the system input data file.

Specifications for thermal plants include:

maximum capacity
minimum capacity
minimum down time
heat rates at various capacity levels
maintenance rates
forced outage rates
fuel costs
operation and maintenance costs

Specifications for hydro plants include:

maximum capacity
minimum capacity
available energy
ramp rate restrictions (Glen Canyon alternative case only)

Specifications for customer load include:

A "typical week" load curve of 168 points, each representing 1 hour, for each month.

Data sources include:

Western Area Power Administration, letter dated July 9, 1990, from Lloyd Greiner to Thomas J. Graff.

Summary of Loads and Resources, Western Systems Coordinating Council, Jan 1, 1990

Electrical World, Directory of Electrical Utilities, Mcgraw Hill, 1990.

National Utility Reference File (NURF) database, U.S. Environmental Protection Agency, 1985, 1986, 1987.

Input data file for SERAM, Southwest Energy and Resource Availability Model, California Energy Commission, 1990.

Fuels Report, California Energy Commission, November 1989.

Elfin input data files for Southern California Edison and Los Angeles Department of Water and Power, Electricity Report 90, California Energy Commission, June 1990.

Elfin input data file for Southern California Edison, California Public Utilities Commission case U 338-E, "Forecast of Operations of the Energy Cost Adjustment Clause for a January 1, 1991 Revision Date (Workpapers)," Southern California Edison Company, June 1990.

EGEAS data file summaries, Stone & Webster Management Associates, for the following utilities:

Salt River Project
Arizona Public Service
Tucson Electric Power Company
Public Service Company of New Mexico
Public Service Company of Colorado
Tri-State Generation and Transmission
Plains Electric and Transmission
Platte River Power Authority
City of Colorado Springs
Colorado Ute Electric Association
Nevada Power Company
Utah Power and Light

Load data were derived from the SERAM input file, which provides state-by-state loads and resources for Arizona, New Mexico, Utah, and Colorado, and includes Tri-State Generation and Transmission Co-op (which includes a portion of Wyoming) and El Paso Electric Company (which includes a portion of Texas). Load data for southern Nevada were derived from the EGEAS summaries. Aggregate load growth in the 1992 through 1995 period averages 2.9% per year for peak loads, and 3.1% per year for energy.

Spinning reserve requirements and commitment targets were set to Western Systems Coordinating Council criteria of 7% of load.

Monthly operating plan data for Glen Canyon were developed by the Bureau of Reclamation and provided by the Western Area Power Administration.

Monthly generation figures for other CRSP projects and SLCA/IP units were held at average levels for each month.

Plant data were derived primarily from the EGEAS summaries, and were cross-checked against the SERAM file, the Electrical World Directory, and the NURF database.

Fuel cost data for coal-fired units were derived primarily from the SERAM data file prepared by the California Energy Commission. These figures are based primarily on Energy Information Administration (EIA) data for 1989, plus escalation rates forecast by the California Energy Commission. Since the EIA data report average fuel prices, which include both fixed- and variable-cost components, these fuel prices tend to overestimate the cost effect of changes in coal-fired generation. Exceptions were fuel costs for the Mohave, Four Corners, and Intermountain units, where variable-cost prices in 1991 were available from the Elfin file created by Southern California Edison Company.

Natural gas fuel cost data were based on the "California Border Price" forecast of the California Energy Commission Fuels Report. These data exclude transportation costs within California. Since these figures include all transportation charges to the California border, and most southwest gas-fired units are closer to the natural gas sources, it is likely that these prices overestimate the cost effect of changes in gas-fired generation.

The following table presents the average coal and gas prices used in the Elfin base-case simulation. Since coal prices are plant-specific the table presents generation-weighted average prices. The natural gas price applies to all gas-fired plants in the simulation.

Fuel Prices

(nominal $/MBtu)

Water year*	Coal	Natural Gas
1992	1.32	2.19
1993	1.42	2.36
1994	1.51	2.56
1995	1.61	2.78
Average escalation rate, 1992-1995	6.8%/yr	8.3%/yr

* 1992 = October 1991 through September 1992

Appendix 2

Results -- Details

Table A1 presents generation by fuel type in each of the cases.

Table A2 presents system marginal costs by time-of-day period and month in the current operations case.

Table A1

Generation by Fuel Type and by Flow Release Pattern and Year (GWh)

Current Operations	1992	1993	1994	1995
Nuclear	16331.5	16307.2	16327.9	16313.3
Coal	85499.2	86799.7	88592.1	90241.6
Gas/Oil	3837.8	4398.1	5171.1	5964.8

Western Proposal	1992	1993	1994	1995
Nuclear	16331.5	16307.2	16327.9	16313.3
Coal	85442.9	86729.8	88523.8	90176.7
Gas/Oil	3905.8	4480.6	5252.9	6044.3

USBR Proposal	1992	1993	1994	1995
Nuclear	16323.9	16307.0	16327.9	16300.1
Coal	85104.2	86362.8	88122.8	89831.0
Gas/Oil	4301.0	4896.2	5700.3	6449.4

GCES Proposal	1992	1993	1994	1995
Nuclear	16329.3	16306.9	16327.9	16313.4
Coal	85061.0	86345.4	88093.4	89793.8
Gas/Oil	4338.8	4915.8	5730.1	6476.8

E/RM Proposal	1992	1993	1994	1995
Nuclear	16329.3	16306.9	16327.9	16313.4
Coal	85058.3	86345.6	88094.3	89793.3
Gas/Oil	4341.9	4915.7	5729.1	6477.1

units are closer to the natural gas sources, it is likely that these prices overestimate the cost effect of changes in gas-fired generation.

The following table presents the average coal and gas prices used in the Elfin base-case simulation. Since coal prices are plant-specific the table presents generation-weighted average prices. The natural gas price applies to all gas-fired plants in the simulation.

Fuel Prices

(nominal $/MBtu)

Water year*	Coal	Natural Gas
1991	1.25	2.08
1992	1.32	2.19
1993	1.42	2.36
1994	1.51	2.56
1995	1.61	2.78
Average escalation rate, 1991-1995	6.5%/yr	7.5%/yr

* 1991 = October 1990 through September 1991

Appendix 2

Results -- Details

Table A1 presents generation by fuel type in each of the cases.

Table A2 presents system marginal costs by time-of-day period and month in the current operations case.

Table A1

Generation by Fuel Type and
by Flow Release Pattern and Year
(GWh)

Current Operations	1991	1992	1993	1994	1995
Nuclear	16060.4	16332.7	16306.4	16327.6	16312.9
Coal	84176.5	85495.8	86781.8	88585.5	90231.5
Gas/Oil	3827.7	3826.1	4418.4	5175.3	5974.4

Alternative I	1991	1992	1993	1994	1995
Nuclear	16050.5	16332.4	16306.4	16327.6	16312.9
Coal	84002.3	85314.0	86576.4	88386.3	90048.9
Gas/Oil	4048.4	4045.8	4657.6	5407.6	6193.0

Alternative II	1991	1992	1993	1994	1995
Nuclear	16122.6	16332.5	16306.4	16327.6	16313.0
Coal	83874.9	85177.0	86484.3	88234.6	89918.0
Gas/Oil	4102.0	4190.1	4759.3	5571.7	6337.7

Alternative IIa	1991	1992	1993	1994	1995
Nuclear	16122.8	16332.4	16306.4	16327.6	16312.9
Coal	83944.0	85264.8	86505.3	88306.7	89943.9
Gas/Oil	4032.9	4102.1	4734.2	5495.1	6306.8

Alternative III	1991	1992	1993	1994	1995
Nuclear	16195.1	16319.7	16301.1	16325.0	16200.4
Coal	83676.1	85023.5	86289.4	88011.2	89843.1
Gas/Oil	4249.2	4379.8	4987.3	5818.2	6540.4

Alternative IIIa	1991	1992	1993	1994	1995
Nuclear	16195.6	16319.7	16301.1	16325.0	16200.3
Coal	83746.8	85119.3	86361.7	88118.7	89825.6
Gas/Oil	4177.3	4284.7	4911.1	5707.6	6554.4

Table A2

Average Marginal Costs by Subperiod and Month

(mills/kWh)

1991		Month											
	Annual	10	11	12	1	2	3	4	5	6	7	8	9
Weekday pk	19.8	19.4	18.7	19.2	20.1	21.0	20.9	19.7	18.8	19.4	20.8	21.0	18.3
Weeknights	15.7	14.5	15.2	16.0	17.3	18.1	17.7	16.1	14.5	13.7	15.1	15.5	14.4
Sat. day	19.3	18.8	18.5	19.1	20.0	20.9	20.8	19.0	18.3	18.5	20.8	20.2	17.2
Weekend other	16.9	16.1	16.5	17.2	18.1	18.7	18.6	17.1	15.7	15.6	17.5	17.2	14.9
Average	18.3	17.6	17.5	18.1	19.1	19.9	19.7	18.3	17.2	17.3	18.9	19.0	16.7

1992		Month											
	Annual	10	11	12	1	2	3	4	5	6	7	8	9
Weekday pk	21.1	20.5	19.6	19.8	21.2	22.2	22.5	21.5	21.4	20.6	22.0	22.2	19.6
Weeknights	15.3	16.1	16.9	18.6	19.5	18.9	17.1	16.0	14.7	16.2	16.6	15.4	
Sat. day	20.5	19.9	19.4	19.6	21.0	22.1	22.3	20.8	20.8	19.4	21.8	21.1	18.2
Weekend other	18.1	17.0	17.4	18.0	19.4	20.1	19.9	18.3	17.5	16.6	18.6	18.2	15.9
Average	19.5	18.6	18.4	18.8	20.2	21.1	21.2	19.9	19.4	18.4	20.0	20.1	17.8

1993		Month											
	Annual	10	11	12	1	2	3	4	5	6	7	8	9
Weekday pk	23.1	21.8	21.0	21.1	23.5	24.5	24.6	23.7	23.6	23.3	24.2	24.3	22.2
Weeknights	18.3	16.3	17.2	18.1	20.5	21.3	20.6	18.8	17.4	16.2	17.6	18.2	17.0
Sat. day	22.5	21.1	20.7	21.0	23.2	24.1	24.3	22.5	22.8	21.9	24.4	23.8	20.2
Weekend other	19.7	18.1	18.6	19.2	21.3	21.9	21.7	20.1	19.1	18.4	20.7	20.3	17.4
Average	21.3	19.8	19.7	20.1	22.4	23.2	23.1	21.8	21.3	20.6	22.1	22.1	19.9

1994		Month											
	Annual	10	11	12	1	2	3	4	5	6	7	8	9
Weekday pk	25.4	24.6	23.7	23.6	25.7	27.0	27.2	26.0	25.9	24.3	26.3	26.2	24.0
Weeknights	19.8	18.0	19.3	20.2	22.1	23.4	22.4	20.1	18.6	17.1	18.7	19.2	18.3
Sat. day	24.8	23.7	23.3	23.3	25.2	26.7	27.0	24.8	25.0	23.7	26.8	26.0	21.8
Weekend other	21.5	20.1	20.9	21.4	23.1	24.1	23.7	21.7	20.6	19.8	22.4	21.9	18.8
Average	23.3	22.2	22.2	22.4	24.3	25.6	25.4	23.8	23.1	21.8	23.9	23.8	21.5

1995		Month											
	Annual	10	11	12	1	2	3	4	5	6	7	8	9
Weekday pk	28.2	27.2	26.2	25.9	28.8	30.4	30.3	29.3	29.2	26.4	29.0	28.6	26.6
Weeknights	21.6	19.4	20.7	21.8	24.7	26.3	25.1	22.3	20.3	18.4	20.2	20.6	19.8
Sat. day	27.5	26.4	25.8	25.6	28.2	29.8	30.2	28.0	28.1	26.2	29.8	28.6	23.9
Weekend other	23.7	22.0	22.7	23.3	25.7	27.0	26.6	24.2	22.8	21.7	24.7	24.0	20.4
Average	25.8	24.4	24.3	24.5	27.2	28.7	28.4	26.6	25.9	23.8	26.4	26.0	23.6

Table A2

Average Marginal Costs by Subperiod and Month

(mills/kWh)

1992	Annual	Month 10	11	12	1	2	3	4	5	6	7	8	9
Weekday peak	21.2	20.6	19.6	19.8	21.3	22.3	22.6	21.7	21.5	20.6	22.0	22.5	19.6
Weeknights	16.7	15.3	16.1	16.9	18.5	19.4	18.7	16.9	15.8	14.6	16.2	16.7	15.4
Sat. day	20.6	19.9	19.4	19.7	21.2	22.2	22.4	20.8	21.0	19.6	22.0	21.2	18.5
Weekend other	18.1	17.0	17.4	17.9	19.4	20.0	19.8	18.2	17.4	16.6	18.7	18.3	15.9
Average	19.5	18.6	18.4	18.8	20.3	21.2	21.2	19.8	19.4	18.4	20.1	20.3	17.8

1993	Annual	Month 10	11	12	1	2	3	4	5	6	7	8	9
Weekday peak	23.2	22.0	21.2	21.2	23.5	24.4	24.6	23.8	23.7	23.3	24.3	24.4	22.1
Weeknights	18.2	16.2	17.1	18.1	20.5	21.3	20.6	18.7	17.3	16.1	17.6	18.2	16.9
Sat. day	22.6	21.2	20.9	21.1	23.3	24.3	24.4	22.5	22.9	22.0	24.6	23.9	20.4
Weekend other	19.8	18.1	18.6	19.2	21.4	22.0	21.7	20.0	19.0	18.4	20.8	20.4	17.5
Average	21.4	19.9	19.8	20.1	22.4	23.3	23.1	21.8	21.3	20.6	22.2	22.2	19.8

1994	Annual	Month 10	11	12	1	2	3	4	5	6	7	8	9
Weekday peak	25.5	24.7	23.7	23.6	25.7	27.0	27.2	26.1	26.0	24.8	26.3	26.3	24.0
Weeknights	19.7	18.0	19.2	20.2	22.1	23.4	22.4	19.9	18.5	17.2	18.7	19.3	18.2
Sat. day	24.9	23.7	23.3	23.4	25.4	26.9	27.0	24.8	25.3	23.8	27.0	26.1	22.0
Weekend other	21.6	20.1	20.8	21.5	23.2	24.2	23.7	21.6	20.6	19.8	22.5	22.0	18.9
Average	23.4	22.2	22.1	22.4	24.4	25.6	25.4	23.8	23.2	22.1	24.0	24.0	21.5

1995	Annual	Month 10	11	12	1	2	3	4	5	6	7	8	9
Weekday peak	28.2	27.3	26.2	26.0	28.8	30.6	30.5	29.4	29.2	26.6	28.9	28.6	26.6
Weeknights	21.5	19.2	20.6	21.8	24.7	26.3	24.9	22.1	20.1	18.3	20.1	20.7	19.8
Sat. day	27.7	26.4	25.8	25.8	28.4	30.3	30.3	27.9	28.3	26.4	30.0	28.7	24.1
Weekend other	23.8	21.9	22.6	23.4	25.8	27.1	26.5	24.1	22.6	21.7	24.8	24.1	20.6
Average	25.8	24.4	24.2	24.5	27.3	28.9	28.4	26.6	25.8	23.8	26.4	26.0	23.7

Testimony of The Environmental Defense Fund

before the

Subcommittee on Water and Power

of the

Senate Energy and Natural Resources Committee

July 24, 1990

Mr. Chairman and members of the Subcommittee, I am Thomas J. Graff, a senior attorney with the Environmental Defense Fund (EDF). Accompanying me here today is Spreck Rosekrans, an EDF economic analyst, who was a principal co-author of the study we have come here to present.

The legislation which you are considering here today seeks to weigh the environmental benefits of modifying the operations of Glen Canyon dam against the economic impacts of those modifications, over the time period while formal and extensive environmental impact studies are completed on the dam's operations. The Glen Canyon Environmental Studies have been underway since 1982, and, in the absence of a decision on new dam operations, current operations continue to have adverse and, in some cases, irreparable environmental impacts. We do not come here today, however, to testify either in favor or against the proposed legislation although there should be little question regarding EDF's policy preference in favor of dam operations which impact least negatively on the Grand Canyon's ecosystem and recreational values.

We have come to testify about the conclusions we have reached regarding the economic costs of various proposed modifications in the dam's operating regime. This of course will not be a complete economic analysis of these proposals. In fact we have made no estimate whatsoever of the economic benefits of modified dam operations including not only such obvious benefits as those which rafters, fishermen, and associated businesses might experience but also those which all who value the ecosystem of the Grand Canyon even without experiencing it firsthand might gain from operational improvements.

Others, however, have made quite outlandish claims regarding the economic cost of these modifications and these we have examined carefully. What we hope to provide the committee is a balanced and hopefully objective analysis of these costs. Before beginning, however, we should note that none of these costs are costs which will be charged to the U.S. taxpayer, nor will they increase the projected federal deficit. Under current federal law, the Western Area Power Administration theoretically is required to recover all of its costs from the preferential power users to whom it sells its output. This would presumably continue under the proposed legislation as well. Indeed the practical fiscal effect of the legislation from the federal government's perspective would simply be to reduce the massive federal subsidy which the power users are currently receiving. From an overall societal perspective, however, there are economic costs of modifying the dam's operations and it is to these costs which we now turn.

For over ten years, EDF and others have been using Elfin (EDF's computer-based simulation model for electric utility operations and planning) to assess economic values associated with electric power production. Elfin is currently in use by regulatory agencies, by all major utilities in California and by a wide array of consultants in California and other parts of the country as well.

EDF became involved in the Glen Canyon Environmental Studies in November 1988, after reviewing Western's "Peach" report. EDF was concerned, along with others, including representatives of the Bureau of Reclamation, that the methodology used in the Peach report was simplistic and tended to overestimate the cost of changing operations. Since that time, EDF has participated, with representatives of Western, USBR and CREDA, on the GCES Power Economics Team, and has made a commitment to insure that economic impacts be evaluated properly so that decisions regarding Glen Canyon dam operations can be made based on accurate estimates of economic impacts. The Power Economics Team has made the decision to use both Elfin and EGEAS (Electric Generation Expansion Analysis System) to analyze the larger customers with firm contracts for CRSP power, and not to use Western's ATP (Alternative Thermal Plant) method.

More recently, at the request of Representative George Miller, Chairman of the House Subcommittee on Water, Power and Offshore Resources, EDF constructed a database representing consumers of Colorado River Storage Project power, and used the Elfin model to conduct simulations of the system with various operating constraints imposed at Glen Canyon Dam. The difference in total costs between the "alternative operations" simulations and the "current operations" simulation is the estimated cost of changing operations. (Using Elfin with this method of analysis is similar to the process the California Public Utilities Commission uses in its annual Energy Cost Adjustment Clause (ECAC) hearings to determine the rates that utilities must pay to independent power producers.)

Five different alternative scenarios for dam operations were simulated. For each scenario the amount of electricity generated each month at Glen Canyon dam did not change, as the amount of electricity generated during a month depends only on the amount of water released that month. The timing of the release of water, however, was changed and therefore the electricity generated by other resources (principally coal- and natural gas-fired power plants) was produced at different times to reflect the changes at Glen Canyon. The cost impact is occasioned by a shift in generation from the less expensive coal plants to more expensive coal plants and to natural gas-fired plants.

- The simulations were conducted for Water Years 1991 through 1995. Hydrologic data for Glen Canyon dam operations was based on expected values as supplied by the Bureau of Reclamation, beginning with adverse conditions for WY 1991 and ending with nearly average conditions in WY 1995. Escalation rates for fuel costs were based on the most reliable estimates available. Changes in expected precipitation or inflation could change the estimated costs of changing operations at Glen Canyon dam.

The least constraining of the alternatives considered required a year-round minimum of 8000 cfs (compared to the current 1000 cfs in winter and 3000 cfs in summer) and a maximum change of 5000 cfs in any hour. Cost estimates for this alternative ranged from $3.9 million in Water Year 1991 to $6.5 million in water Year 1995. The most constraining of the alternatives simulated was the "baseload" option, in which the Colorado River would run at a constant flow each month to satisfy the Bureau of Reclamation's Annual Operating Plan. Cost estimates for this alternative ranged from $8.2 million in Water Year 1991 to $19.0 million in Water Year 1995. For additional results and more thorough explanation of the alternatives, we have attached the report to this testimony and request respectfully that it be made a part of the hearing record.

How these increased costs are passed along would depend on whether Western maintained its present interim marketing plan (and changed its schedule of purchasing additional power to supplement its contracts) or Western changed its contracts (firm power customers must then make their own deals for supplemental power). Assuming the former option were selected and were expressed as an increase in Western's firm power rate, which now averages only approximately 1.0 cents/kWh, the rate would increase only by a range of .07 to .33 cents/kWh, leaving the rate for firm power still a substantial bargain compared to market rates.

The report EDF prepared also estimated changes in the emissions of air pollutants that changes in Glen Canyon dam operations would cause in changed operations of thermal plants. Simulation results indicate a small net decrease in emissions of carbon dioxide and oxides of nitrogen for most years and alternatives (due to a slight shift from coal to natural gas), and a small net increase in emissions of sulfur dioxide for most years and alternatives (due to a slight increase in generation at some of the "dirtier" coal plants). Details are contained in the report.

Mr. Chairman, that conclude EDF's testimony. We would be pleased to answer any questions any committee member might have, either now or in the future, regarding the economic impacts of varying Glen Canyon dam's operating regime. We do remain committed to working with USBR, WAPA, CREDA and others in providing the highest possible quality information to help illuminate the potential alternative courses of action. Thank you for your attention.

Estimates of Economic Impacts of Implementing Interim Flow Release Patterns at Glen Canyon Dam

for the

U.S. House of Representatives
Committee on Interior and Insular Affairs

Subcommittee on Water, Power and
Offshore Energy Resources

Environmental Defense Fund
Oakland, California
(415) 658 8008

July 12, 1990

Executive Summary

Legislation has been introduced (HR4498) which would direct the Secretary of Interior to implement flow release constraints at Glen Canyon Dam on an interim basis, pending completion of the Environmental Impact Statement assessing the effect of current operations and alternatives on the Grand Canyon. This study uses a computer-based simulation model to examine the net economic impacts of changes in power system operations resulting from a set of alternative release requirement scenarios. In addition, emissions impacts of the changes are also examined.

Flow release constraints at Glen Canyon Dam do not change the overall amount of electric energy that can be generated; instead, this energy is generated at different times. There is an economic cost because there is a loss in the operating flexibility of the hydroelectric generating plant. More costly fossil-fueled powerplants must be used in a less efficient manner.

Three basic alternative flow release requirement scenarios were examined. The first scenario requires minimum releases to be raised from the current 1,000 cubic feet per second (cfs) in winter and 3,000 cfs in summer to 8,000 cfs year round. In addition, releases would not be allowed to change by more than 5,000 cfs in any one hour (currently there is no restriction on how fast releases may be increased or decreased). Power system costs are estimated to increase $3.9 million in 1991 in this case compared to current operations.

A second alternative additionally constrains the maximum release rate to 20,000 cfs for power generation purposes, compared to the current maximum release rate of 31,500 cfs. In this case power system costs are $4.7 million in 1991 compared to current operations.

A third alternative would require constant releases each month (that is, there would be no fluctuating flows). This alternative results in power system costs of $8.2 million in 1991 compared to current operations.

Since the second and third alternatives constrain the generating capability of the Glen Canyon Dam below its physical capability, a measure that would increase flexibility for power operations while having only a small environmental impact is available. This would be to allow the maximum release rate to be exceeded on an emergency basis when power system reserve capacity is required to be used. With this measure the costs of the second alternative would be reduced from $4.7 to $3.9 million in 1991. The costs of the third alternative would be reduced from $8.2 to 6.8 million in 1991.

These costs are a very small percentage -- significantly less than 1% -- of overall power system costs, even when allocated entirely to the utilities which currently receive Glen Canyon power.

Emissions impacts are even smaller, and in several cases positive. The change in operations slightly increases sulfur dioxide emissions, while nitrogen oxide and carbon dioxide emissions generally decrease.

Estimates of the Economic Impacts

of Implementing Interim Flow Release Patterns

at Glen Canyon Dam

I. Introduction

The United States Department of the Interior is currently preparing an Environmental Impact Statement to assess flow release patterns and proposed changes in release requirements at Glen Canyon dam. Since current operations -- which are largely geared toward optimizing power production -- are causing environmental damage within the Grand Canyon, legislation has been introduced that would impose release requirements on an interim basis, pending completion of the Environmental Impact Statement. Such interim requirements would restrict the extent to which releases would be optimized only for power production purposes, and thus could be expected to increase the economic costs of meeting power demands in the Southwest region. This study uses a computer-based utility system simulation model to forecast the magnitude of potential cost increases under several different flow release requirement scenarios.

In addition, the effects of the different release requirements on powerplant emissions of sulfur oxides, nitrogen oxides, and carbon dioxide are also forecast during the interim period 1991 through 1995.

The alternative flow release scenarios examined in this study can be compared to current operations at Glen Canyon dam. Current operations allow water to be released from the dam at a maximum rate of 31,500 cubic feet per second (cfs) for power generation purposes. (This rate can be exceeded if flood control needs require it.) The release rate must be at least as great as 1,000 cfs in winter (October through March) and at least 3,000 cfs in summer (April through September). There is no restriction on how fast releases can be changed from hour to hour (the "ramp rate").

The alternative flow release scenarios illustrate the range of impacts that may occur as a result of interim flow release requirements at Glen Canyon dam. The first alternative raises the minimum release requirement. The second alternative simultaneously reduces the maximum release. A third alternative is a maximum-cost-effect scenario: the minimum release requirement equals the maximum release requirement each month; that is, there is virtually no variation in release rates within a month.

The first alternative release scenario requires the release rate to be at least 8,000 cfs year round. The maximum rate of 31,500 cfs would be retained. In addition, the release rate could not change by more than 5,000 cfs over a one-hour period (i.e., the ramp rate could not be greater than 5,000 cfs per hour).

The second alternative release scenario would also require a minimum release rate of 8,000 cfs year round. The maximum release rate would be restricted to 20,000 cfs for power generation purposes. The maximum ramp rate would again be 5,000 cfs per hour.

A third alternative would require near-constant releases each month. This is referred to as "baseload" operation. Release rates would vary from month to month in accord with water storage, delivery, and flood control requirements.

In addition to these three basic alternatives, this study examines two variations to the second and third alternatives. The variations concern the extent to which the physical capacity of Glen Canyon dam can be used for emergency reserve support. These variant cases allow greater flexibility in the use of Glen Canyon capacity by allowing the maximum release rate to be exceeded on those infrequent occasions when system reserve capacity must be called on. For example, current operations currently hold 114 Megawatts of Colorado River Storage Project peaking capacity for reserve support. Since the second alternative case has a normal maximum release rate of 20,000 cfs, allowing the release rate to increase to 31,500 cfs for reserve purposes creates reserve capacity of approximately 442 Megawatts. In the third alternative, baseload operation case, the level of reserve capacity created by allowing peaking generation on an emergency basis varies from month to month depending on the level of releases each month.

In summary, the cases examined are:

	Minimum release (cfs)	Maximum release (cfs)	Maximum ramp rate (cfs/hr)	Reserve capacity (MW)
Current operations	1,000/3,000	31,500	-	114
Alternatives:				
I - 8,000 cfs minimum	8,000	31,500	5,000	114
II - 8,000 min + 20,000 max	8,000	20,000	5,000	114
IIa - (with reserve capacity)	8,000	20,000	5,000	442
III - baseload	-	-	~0	114
IIIa - (with reserve capacity)	-	-	~0	~400-850

How do these different release requirements affect power generation costs? Electric generation is most valuable at peak-load times (such as summer afternoons when air-conditioning requirements are greatest) because electric utilities typically have to call upon higher-cost generation resources to meet these higher loads. In a typical month water supply will not be great enough to allow a 31,500 cfs release rate around the clock. Instead, the value of water for power generation can be maximized by releasing the limited amount of water preferentially at peak-load times, and as little as possible at other times. The current operations release requirements allow a great deal of flexibility to do this. The resulting fluctuating flows are the subject of the current environmental investigations.

Under alternative I, the minimum release requirement is raised to 8,000 cfs. While there is no difference in the total amount of water released from the dam in a month, and thus no difference in the total amount of energy generated, less of that total is available to be scheduled at peak-load times, since there are greater requirements for minimum releases at all times. Thus, alternative I shifts some energy generation from peak-load times to non-peak-load times. Other, higher-cost coal and natural gas resources must be turned on at peak-load times, thus increasing costs. The additional hydroelectric generation at non-peak times means that the fossil-fuel plants will generate less at these times, thereby saving money. Since the fossil-fuel plants which generate less are lower-cost resources, the off-peak savings will not be as great as the on-peak costs. In addition, the ramp-rate restriction also constrains flexibility to meet peak-load requirements.

Alternative II further restricts the ability to use Glen Canyon generation at peak-load times. Alternative III eliminates the ability to optimize hydroelectric generation for peak-time use.

Alternatives IIa and IIIa allow the full capacity of Glen Canyon dam, up to the 31,500 cfs release rate, to be used on an emergency basis. This additional flexibility means that power system operators do not have to commit more expensive, fossil-fuel resources for purposes of reserve support.

II. Study Method

This study calculates the economic effects of changes in the hour-to-hour scheduling of Glen Canyon Dam generation by simulating the operation of the most directly affected electric systems of which the Glen Canyon powerplant is a component. The interconnected western power grid which includes Glen Canyon Dam is a far-flung entity extending through British Columbia. Power from the Colorado River Storage Project (CRSP), a set of dams on the Colorado River, of which Glen Canyon is by far the major component, has regularly been sold as far away as California. This study restricts attention to the power systems most directly affected by changes in Glen Canyon generation. These include customers of Colorado River Storage Project power (municipal and publicly-owned utilities in Arizona, New Mexico, Utah, Colorado, and southern Nevada), and, for those customers which do not have their own generating plants, their alternative suppliers (generally investor-owned utilities in the same region).

The electric system simulation used in this study focuses on the real economic costs of changing operations. That is, the simulation examines the physical and resource changes involved in burning fuel and generating electricity, rather than financial changes that come with different power transactions. Thus, the increased profit that utility A may be able to make when it increases sales to utility B is not a subject of this study. The cost of the additional fuel that utility B burns to supply utility A is. This study takes a net economic impacts perspective across utilities rather than the perspective of any single utility.

A single utility or entity such as the Western Area Power Administration (which markets and distributes Colorado River Storage Project Power) will consider only its own "wins" and "losses" which result from power transactions. These transactions will ordinarily include a mark-up component (which, from an economic perspective, represents a transfer payment rather than a resource cost). "Winners" and "losers" may largely balance out when all such entities are considered. This study considers only the net loss over all such entities; it does not calculate any single entity's position.

There are several aspects of the distribution of the net economic cost that are known, however. Increases in power costs will fall on Colorado River Storage Project firm customers in either of two ways. One possibility is that the firm customers' share of Glen Canyon resources will be changed in accordance with changes in Glen Canyon operations, thereby making the power less valuable and requiring these utilities to generate or purchase make-up power at on-peak times. Alternatively, the Western Area Power Administration could continue to supply power in accord with pre-existing contracts and will itself purchase make-up power. In this case rates to firm customers will increase to cover Western's costs. For these reasons the net cost impacts per kilowatt-hour are most appropriately attributed to those kilowatt-hours delivered to firm customers.

An additional aspect of the distribution of net economic costs that is also known is the effect on the federal treasury. Since Western currently markets Glen Canyon power at a cost well below its free-market value, Western will be able to adjust firm power rates to recover any increases in its costs. Aside from slight differences in the timing of the repayment of Western's costs there is no effect on Western's payments to the federal treasury.

The simulation of the power systems is performed through the use of the Elfin computer model. The Elfin electric utility simulation model was developed by the Environmental Defense Fund, and is currently widely used in California and elsewhere in the country. Some of the users and uses of the Elfin model are summarized in Appendix 1. In this study the Elfin model simulates the operation of more than one hundred generating units in the Southwest region.

III. Results

The Elfin model measures the total costs of producing electricity for the simulated power systems for each year of the study period under each case. These costs include the costs of powerplant fuel and variable operation and maintenance expenses. (These costs do not include fixed costs such as interest, or costs such as administrative and general expenses which are not expected to change as a result of changes in Glen Canyon operations.) Table 1 shows these total production costs for each flow release scenario and year from 1991 through 1995.

In addition, table 1 calculates the change in total production costs in each case compared to the current operations case. Thus, alternative I, the

8,000 cfs minimum release case, results in increased costs of $3.9 million in 1991 compared to current operations. Alternative II, which also includes a 20,000 cfs maximum release requirement, results in a larger increase in costs, $4.7 million in 1991. Alternative IIa, which allows additional operating flexibility during emergency conditions, mitigates the additional cost effect; the increase in costs is $3.9 million compared to current operations.

Alternative III, the baseload flow release pattern, has the highest cost impacts. In 1991, the baseload alternative costs $8.2 million compared to current operations. Alternative IIIa, which provides peaking capacity for emergency reserve support, reduces the additional cost to $6.8 in 1991.

Table 1 also shows the cost increases compared to the base case as a percentage of total costs. In general, the percentage impacts increase over time. This occurs as the result of two factors: first, power system loads are forecast to increase approximately 3% per year during this period; and second, Glen Canyon hydroelectric generation is also forecast to increase, since reservoirs are currently low and water supplies are expected to increase under expected average hydrologic conditions. The first factor makes hydroelectric generation relatively more valuable over time, since increasing loads means that higher-cost thermal resources must be used to meet these loads. The second factor means that Glen Canyon hydroelectric generation is larger share of the generation "mix," and any constraint on the operational flexibility of this resource will have a greater relative impact.

Finally, the last section of table 1 shows the impact of the cost increases on Colorado River Storage Project firm customers. These impacts are calculated on a cost per kilowatt-hour basis. For example, alternative I would increase costs to CRSP firm customers by 0.07 cents per kilowatt-hour in 1991. Since the rates for CRSP firm power average approximately 1 cent per kilowatt-hour currently, this represents an approximately 7% increase in the cost of CRSP power. These figures overstate the cost impact of the changes, however. The cost of CRSP power represents on average only a small fraction of the total costs of the utilities which receive this power. These utilities generate or purchase the balance of their power requirements from other sources, and in addition have interest costs, distribution system costs, operation and maintenance costs, and so forth. Thus, the increase in rates to the residential and business customers of these utilities is small indeed; on average less than 0.3% in this case.

Figure 1 charts the change in total costs for each case compared to current operations by year.

Tables 2 through 4 show powerplant emissions results under each case. Table 2 shows sulfur dioxide emissions, table 3 shows nitrogen oxide emissions, and table 4 shows carbon dioxide emissions. Sulfur dioxide emissions increase in the alternative cases, while in many cases nitrogen oxide emissions decrease. Carbon dioxide emissions decrease in the alternative cases. The decreases in carbon dioxide emissions occur because of shifts from coal-fired generation (which emits proportionately more carbon dioxide) to natural gas-fired generation. Carbon dioxide emission rates per

TABLE 1

Total Production Costs by Flow Release Pattern
and Water Year *

Total Costs (million $)

	1991	1992	1993	1994	1995
Current operations	1680.9	1793.8	1947.5	2106.5	2302.3
Alternatives:					
I - 8,000 cfs minimum	1684.7	1797.8	1952.0	2111.9	2308.8
II - 8,000 min + 20,000 max	1685.5	1800.4	1955.2	2116.8	2313.7
IIa - (with reserve capacity)	1684.7	1799.1	1953.8	2114.3	2312.4
III - Baseload	1689.0	1804.5	1960.6	2123.5	2321.3
IIIa - (with reserve capacity)	1687.7	1803.0	1958.6	2120.4	2321.3

Change From Current Operations (million $)

I - 8,000 cfs minimum	3.9	4.0	4.5	5.4	6.5
II - 8,000 min + 20,000 max	4.7	6.6	7.8	10.2	11.4
IIa - (with reserve capacity)	3.9	5.3	6.4	7.8	10.1
III - Baseload	8.2	10.7	13.2	17.0	19.0
IIIa - (with reserve capacity)	6.8	9.2	11.2	13.8	19.0

Change From Current Operations (percent)

I - 8,000 cfs minimum	0.23%	0.22%	0.23%	0.25%	0.28%
II - 8,000 min + 20,000 max	0.28	0.37	0.40	0.49	0.50
IIa - (with reserve capacity)	0.23	0.29	0.33	0.37	0.44
III - Baseload	0.49	0.60	0.68	0.81	0.83
IIIa - (with reserve capacity)	0.41	0.52	0.57	0.66	0.82

Cost per kWh of CRSP Firm Sales (cents per kWh)

I - 8,000 cfs minimum	0.07	0.07	0.08	0.09	0.11
II - 8,000 min + 20,000 max	0.08	0.12	0.14	0.18	0.20
IIa - (with reserve capacity)	0.07	0.09	0.11	0.14	0.18
III - Baseload	0.14	0.19	0.23	0.30	0.33
IIIa - (with reserve capacity	0.12	0.16	0.20	0.24	0.33

* Water year 1991 equals October 1990 through September 1991.

FIGURE 1

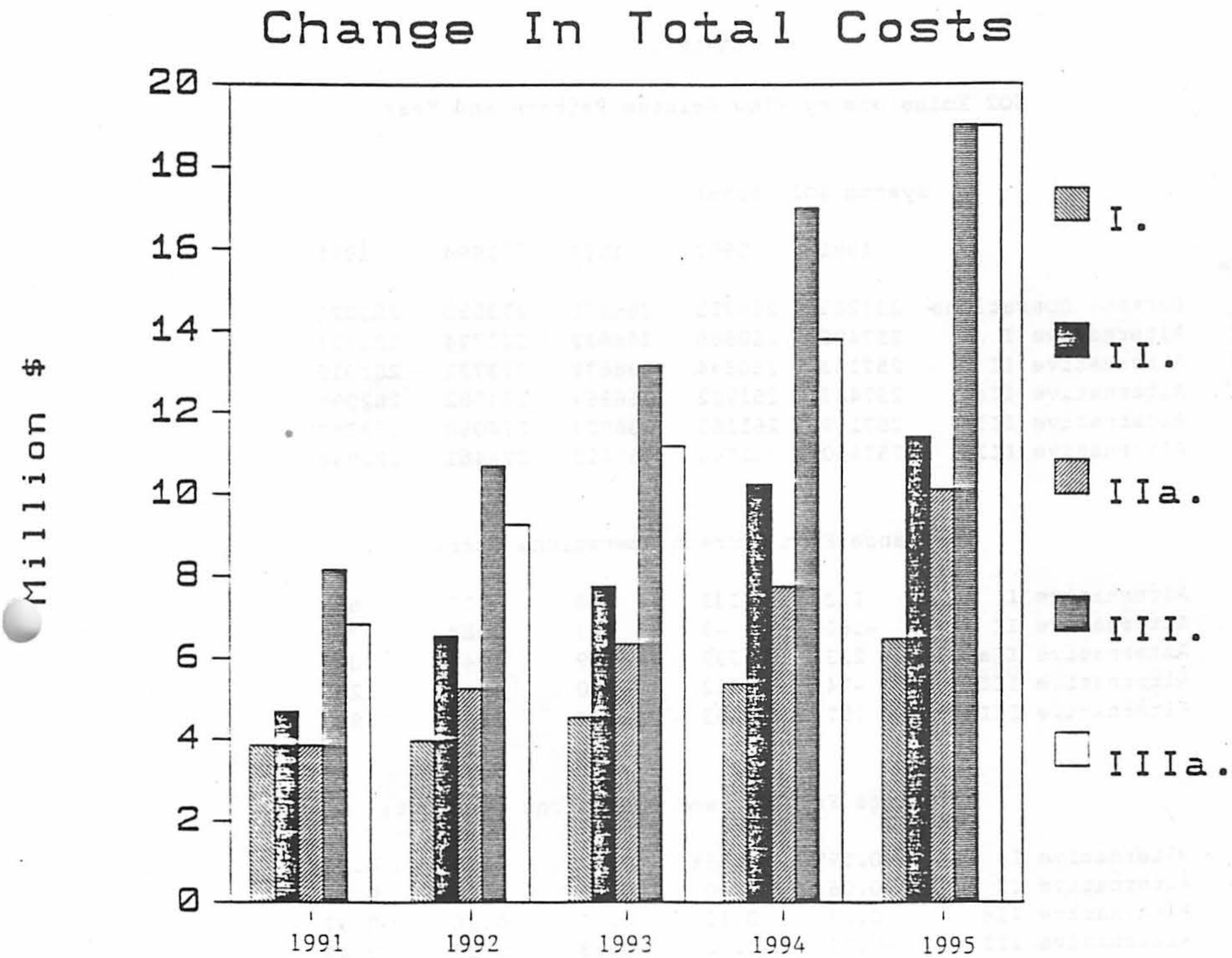
Change In Total Costs
Million $
20
18
16
14
12
10
8
6
4
2
0
1991
1992
1993
1994
1995
I.
II.
IIa.
III.
IIIa.

TABLE 2

SO2 Emissions by Flow Release Pattern and Year

System SO2 (tons)

	1991	1992	1993	1994	1995
Current operations	257263	260853	266175	273038	281021
Alternative I	257495	260988	266632	273774	281704
Alternative II	257103	260844	266672	273721	281816
Alternative IIa	257487	261252	266964	274082	282055
Alternative III	257189	261165	266925	274050	282257
Alternative IIIa	257460	261546	267419	274461	282948

Change From Current Operations (tons)

Alternative I	232	135	458	737	683
Alternative II	-161	-9	497	684	795
Alternative IIa	223	399	789	1044	1034
Alternative III	-74	312	750	1012	1235
Alternative IIIa	197	693	1244	1424	1927

Change From Current Operations (percent)

Alternative I	0.09%	0.05%	0.17%	0.27%	0.24%
Alternative II	-0.06	0.00	0.19	0.25	0.28
Alternative IIa	0.09	0.15	0.30	0.38	0.37
Alternative III	-0.03	0.12	0.28	0.37	0.44
Alternative IIIa	0.08	0.27	0.47	0.52	0.69

TABLE 3

NOx Emissions by Flow Release Pattern and Year

System NOx (tons)

	1991	1992	1993	1994	1995
Current operation	337634	342820	348493	356382	363839
Alternative I	337422	342583	348252	356166	363645
Alternative II	337169	342423	348460	356229	364145
Alternative IIa	337242	342550	348193	356097	363547
Alternative III	336984	342376	348370	355978	364607
Alternative IIIa	336934	342399	348352	356038	363829

Change From Current Operations (tons)

Alternative I	-212	-237	-241	-216	-194
Alternative II	-465	-398	-33	-153	306
Alternative IIa	-392	-270	-299	-285	-292
Alternative III	-650	-444	-123	-404	767
Alternative IIIa	-700	-422	-140	-344	-10

Change From Current Operations (percent)

Alternative I	-0.06%	-0.07%	-0.07%	-0.06%	-0.05%
Alternative II	-0.14	-0.12	-0.01	-0.04	0.08
Alternative IIa	-0.12	-0.08	-0.09	-0.08	-0.08
Alternative III	-0.19	-0.13	-0.04	-0.11	0.21
Alternative IIIa	-0.21	-0.12	-0.04	-0.10	0.00

TABLE 4

CO2 Emissions by Flow Release Pattern and Year

System CO2 (millions of tons)

	1991	1992	1993	1994	1995
Current operation	98.93	100.46	102.30	104.48	106.71
Alternative I	98.92	100.44	102.27	104.46	106.70
Alternative II	98.85	100.42	102.29	104.45	106.74
Alternative IIa	98.87	100.44	102.26	104.45	106.69
Alternative III	98.79	100.40	102.27	104.42	106.83
Alternative IIIa	98.79	100.42	102.28	104.43	106.77

Changes From Current Operations (thousands of tons)

Alternative I	-17.18	-24.60	-27.30	-20.30	-10.20
Alternative II	-87.72	-46.40	-5.80	-25.40	25.20
Alternative IIa	-67.10	-27.30	-35.90	-30.20	-25.60
Alternative III	-141.60	-58.90	-30.60	-53.00	120.90
Alternative IIIa	-140.00	-45.20	-18.70	-47.00	58.10

Change From Current Operations (percent)

Alternative I	-0.02%	-0.02%	-0.03%	-0.02%	-0.01%
Alternative II	-0.09	-0.05	-0.01	-0.02	0.02
Alternative IIa	-0.07	-0.03	-0.04	-0.03	-0.02
Alternative III	-0.14	-0.06	-0.03	-0.05	0.11
Alternative IIIa	-0.14	-0.05	-0.02	-0.04	0.05

Btu of fuel do not vary significantly among coal plants, nor do they vary among natural gas plants. On the other hand, sulfur dioxide emission rates vary from coal plant to coal plant depending on the sulfur content of the coal fuel. These increases would be relatively easy and inexpensive to mitigate by including emissions factors in the optimization criteria used to operate the power system.

IV. Conclusion

Changes in flow release patterns at Glen Canyon dam which restrict the degree to which these flow releases can be optimized purely for power generation purposes do increase power system generating costs in the southwest region. More restrictive flow release patterns cause greater increases in cost. The cost increases range from $3.9 million dollars per year in 1991 under an 8,000 cfs minimum release requirement to a maximum of $8.2 million dollars per year in 1991 under a baseload alternative. The greater increases in cost can be mitigated to some extent by allowing operating flexibility on an emergency basis.

Only one kind of operating flexibility increase was considered in this study: allowing higher maximum release rates for emergency reserve purposes. There are other methods of increasing operating flexibility which should be considered for both power generation and environmental goals. For example, monthly water releases are determined by the Bureau of Reclamation considering goals primarily for water delivery and flood control. To the extent there is remaining flexibility in month-to-month water releases these will be scheduled to optimize power generation. With changes in daily flow release patterns these month-to-month schedules could be re-optimized. Such re-optimization, which could further reduce the costs of changing flow release patterns, was not examined in this study.

In addition, flow release patterns which enhance environmental protection may be less generally constraining than the flow release patterns examined in this study. For example, protection of fish species may require restrictive flow release patterns at only certain times during the year.

An additional method of ameliorating cost impacts was also not considered in this study: energy efficiency improvements. Given the low price of Colorado River Storage Project power, utility customers have had relatively little incentive to promote energy conservation and load management among their residential and business consumers. Current research points to significant remaining potentials for energy efficiency improvements among electricity users at costs below the costs of thermal generation. Load management, by cutting peak-period electric demands, has the potential to directly mitigate the effects of restricting peak-period generation at Glen Canyon dam. Potential cost savings from increased energy efficiency would quickly outweigh the cost increases due to changing flow release patterns at Glen Canyon dam.

Appendix 1

Study Method

A. Power Systems Simulation

1. The Elfin Model

The method used in this study to calculate the economic costs of changing operations at Glen Canyon dam is to simulate changes in Glen Canyon electric generation within the context of the power systems most directly affected by those changes. Since these power systems involve more than a hundred electric generating units in portions of seven states, and since power system operations are extremely complex, a computer-based model is necessary for this task.

The "Elfin" electric utility production cost simulation model is used in this study. The Elfin model was developed by the Environmental Defense Fund. The model is currently the primary analysis tool used by the staffs of both the California Public Utilities Commission and the California Energy Commission. The Southern California Edison Company uses Elfin as its primary tool for long-range planning. In addition, Elfin is used by a number of consulting and engineering firms in California and elsewhere.

The Elfin model is used by these organizations for a variety of purposes related to the operation of electric generation systems. For example, before the California Public Utilities Commission Elfin is used to make short-term (one year) forecasts of fuel use and marginal energy costs for purposes of setting electric rates and "Qualifying Facility" (cogeneration and independent power producer) purchase prices. The model is also used by both of the California regulatory commissions and others to do long-term planning. For example, the model is used to determine what new plants would be most cost effective. It is also used to determine what levels of conservation and demand-side management would be most cost effective.

In addition, the Elfin model has been recommended for use, along with the Electric Power Research Institute's EGEAS model, in the Department of Interior's Environmental Impact Statement process currently under way for Glen Canyon operations. The Glen Canyon Environmental Studies' Power Economics Team, of which the Environmental Defense Fund is a participating member, conducted "prototype" studies to determine acceptable methods for calculating the economic impacts of changes in operations at Glen Canyon dam. Three different methods were compared: the Western Area Power Administration's "Alternative Thermal Plant" method; the EGEAS model; and the Elfin model. The prototype studies using each of these methods were conducted by Western Area Power Administration, Stone & Webster Management Associates, and the Environmental Defense Fund, respectively. The Alternative Thermal Plant method was judged to be less useful than either of the models because only the models could take into account the complexity and range of impacts involved in the power system. The EGEAS model was favored because of its ability to make "optimum generation expansion decisions" in the long run, when new generating capacity may be necessary to replace lost peaking capacity from Glen Canyon (since there is currently significant excess capacity in the southwest region the issue of new generating capacity is not particularly relevant to interim operating conditions at Glen Canyon). The Elfin model was recommended as a valuable cross-check for EGEAS results.

2. What the Elfin Model Does

The Elfin electric utility production simulation model simulates the production of electricity by generating units to meet customer demands. The Elfin model begins with the "load shape" -- the hour-by-hour demand for electricity. The model then uses data on the electric generating plants available to meet load to simulate how these plants will be operated. Data such as the capacity of each plant, the type and cost of fuel each plant uses (or the availability of water for hydroelectric generation), the efficiency of each plant, and the maintenance requirements and reliability of each plant are used in the simulation. The simulation is "probabilistic;" an important factor in the operation of electric systems is the outages of generating units due to mechanical breakdowns. Since such outages cannot be forecast except on an average, expected basis, the model weighs the probability of each combination of outage events in calculating its results.

The model simulates the operation of electric systems with essentially the same goal as power system operators: to meet electric needs at minimum cost subject to constraints on reliability, operating flexibility, and other factors. The Elfin model includes a "commitment" algorithm and a "spinning reserve" algorithm. The commitment algorithm decides when slow-start plants must be committed for reliability purposes (that is, when each slow-start plant must be started up, with the constraint that in order to be available for peak-period loads, such plants must remain running at a minimum level during non-peak times). The spinning reserve algorithm decides when quick-start units (such as combustion turbines), which would otherwise not be economic, must be brought on-line to meet operating reserve requirements.

B. System Definition for the Elfin Simulations

In this study, the Elfin model simulates operations on a month-by-month basis, with each month represented by a "typical week" within that month.

This monthly simulation is conducted for power systems covering portions of seven states. The Colorado River Storage Project (CRSP), of which Glen Canyon dam is the major component, has over one-hundred customers for firm electric power, mostly in Arizona, New Mexico, Utah, Colorado and southern Nevada. Most of these customers are small utilities which have no generating resources of their own, but purchase power from larger neighboring utilities when they have needs in excess of their firm contract power. Consequently all major utilities and thermal generating units in these states are potentially affected by a change in operations at Glen Canyon. (Interconnected utilities also own plants or portions of plants in Wyoming and Texas.)

The simulated system consists of 70 coal-fired units, 3 nuclear generating units, 58 oil- or gas-fired steam turbines or combined-cycle units, a large number of combustion turbines, all CRSP units (including, of course, Glen Canyon), most of the non-federally owned hydro projects in the region and two pumped-storage plants.

All of these systems are modelled as an interconnected, bulk system in the Elfin simulations for this study. While significant portions of the system are subject to a formal power pooling agreement that coordinates reserve capacity sharing and economy energy transactions, there are still significant transmission constraints and coordination constraints within the larger interconnected area. The transmission and coordination constraints have been approximated within this study's Elfin simulations by insuring that certain minimum levels of local generation would occur in each sub-area. This is accomplished by making plants in each sub-area "must-run" plants, which must be committed for local generation and reliability purposes regardless of economics.

The bulk-system simulation used in this study is not as sophisticated as the approach recommended for the Environmental Impact Statement by the Power Economics Team. The recommended approach is to model a number of utilities which receive Glen Canyon power on a utility-by-utility basis, taking specific account of their interconnections with neighboring utilities. This detailed approach is deemed necessary in order to measure utility-specific impacts of both changes in Glen Canyon generation <u>and</u> changes in Colorado River Storage Project firm contracts. Neither sufficiently detailed data nor time were available for such a detailed approach in this study; since neither utility-specific impacts nor changes in firm contracts are of interest in this study, such a detailed approach was deemed unnecessary.

The Western Area Power Administration (WAPA) is in charge of marketing and distributing CRSP power. Since actual energy and capacity available from CRSP generating units varies from year-to-year with hydrological conditions, and this energy and capacity may be greater or less than WAPA's firm contract obligations, WAPA also conducts transactions in order to meet its firm contract obligations, or to sell surpluses above the firm contract amounts. The Elfin simulations do not separate these transactions in any special way. Instead, such transactions are modelled concurrently with other system power flows.

C. Notes on Data and Sources

As described above, the Elfin production cost model dispatches generating resources subject to operating constraints in order to serve customer load as economically as possible. Thus, both loads and resources must be specified in the system input data file.

Specifications for thermal plants include:

- maximum capacity
- minimum capacity
- minimum down time
- heat rates at various capacity levels
- maintenance rates
- forced outage rates
- fuel costs
- operation and maintenance costs

Specifications for hydro plants include:

- maximum capacity
- minimum capacity
- available energy
- ramp rate restrictions (Glen Canyon alternative case only)

Specifications for customer load include:

A "typical week" load curve of 168 points, each representing 1 hour, for each month.

Data sources include:

Western Area Power Administration, letter dated July 9, 1990, from Lloyd Greiner to Thomas J. Graff.

Summary of Loads and Resources, Western Systems Coordinating Council, Jan 1, 1990

Electrical World, Directory of Electrical Utilities, Mcgraw Hill, 1990.

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Fuels Report, California Energy Commission, November 1989.

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EGEAS data file summaries, Stone & Webster Management Associates, for the following utilities:

Salt River Project
Arizona Public Service
Tucson Electric Power Company
Public Service Company of New Mexico
Public Service Company of Colorado
Tri-State Generation and Transmission
Plains Electric and Transmission
Platte River Power Authority
City of Colorado Springs
Colorado Ute Electric Association
Nevada Power Company
Utah Power and Light

Load data were derived from the SERAM input file, which provides state-by-state loads and resources for Arizona, New Mexico, Utah, and Colorado, and includes Tri-State Generation and Transmission Co-op (which includes a portion of Wyoming) and El Paso Electric Company (which includes a portion of Texas). Load data for southern Nevada were derived from the EGEAS summaries. Aggregate load growth in the 1991 through 1995 period averages 2.9% per year for peak loads, and 3.1% per year for energy.

Spinning reserve requirements and commitment targets were set to Western Systems Coordinating Council criteria of 7% of load.

Monthly operating plan data for Glen Canyon were developed by the Bureau of Reclamation and provided by the Western Area Power Administration.

Monthly generation figures for other CRSP projects and SLCA/IP units were held at average levels for each month.

Plant data were derived primarily from the EGEAS summaries, and were cross-checked against the SERAM file, the Electrical World Directory, and the NURF database.

Fuel cost data for coal-fired units were derived primarily from the SERAM data file prepared by the California Energy Commission. These figures are based primarily on Energy Information Administration (EIA) data for 1989, plus escalation rates forecast by the California Energy Commission. Since the EIA data report average fuel prices, which include both fixed- and variable-cost components, these fuel prices tend to overestimate the cost effect of changes in coal-fired generation. Exceptions were fuel costs for the Mohave, Four Corners, and Intermountain units, where variable-cost prices in 1991 were available from the Elfin file created by Southern California Edison Company.

Natural gas fuel cost data were based on the "California Border Price" forecast of the California Energy Commission Fuels Report. These data exclude transportation costs within California. Since these figures include all transportation charges to the California border, and most southwest gas-fired

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Glen Canyon: The Economic Costs

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Abstract

Revenues from power produced at Glen Canyon Dam are used to support Colorado River Storage Project (CRSP) purposes, to pay O&M costs, and to repay construction costs. Generation of peaking power causes downstream releases and river stage to fluctuate on an hourly basis. This has been shown to impact the downstream physical and biological environment. A number of alternative management regimes are being considered to reduce these impacts. This paper discusses the potential impacts of these regimes on power production.

Introduction

Generation of peaking power at Glen Canyon Dam typically results in hourly fluctuations in release and river stage. These fluctuations significantly affect the quality of white-water boating and angling (Bishop, et al. 1987), and the maintenance of the downstream trout fishery. Fluctuations are also thought to affect the reproduction, recruitment, and survival of native fish. Further, historic operations have been implicated in the depletion of pre-dam alluvial deposits with associated impacts on cultural and riparian resources. The Glen Canyon Dam Environmental Impact Statement (GCDEIS) was initiated in 1990 to examine options which "... minimize-- consistent with law-- adverse impacts on downstream environmental and cultural resources and Native American interests..." (U.S. Department of the Interior 1993).

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Analysis

Nine operational alternatives and their impacts are described in detail in the forthcoming GCDEIS. These range from operations which are largely unrestricted to baseloading of the powerplant. The parameters affecting operation of Glen Canyon Dam are summarized by alternative in Table 1.

Table 1. Summary of Parameters Affecting Generation

Alternative	Upramp rate (cfs/hr)	Downramp rate (cfs/hr)	Minimum Flow (cfs)	Allowable Daily Change (cfs)
No Action	unlimited	unlimited	1,000 winter 3,000 summer	30,500
Maximum Powerplant Capacity	unlimited	unlimited	1,000 winter 3,000 summer	32,200
High Fluctuating Flow	unlimited	5,000	3,000-8,000 depending on month	15,000 - 22,000
Moderate Fluctuating Flow	4,000	2,500	5,000	45% monthly flow
Low Fluctuating Flow	2,500	1,500	5,000 night 8,000 day	5,000-8,000
Seasonally Adjusted Fluctuating Flow	8,000 Oct-Apr 2,500 May-Sep	1,500	5,000 night 8,000 day	45% Oct-May 2,000 June 2,500 Jul-Sep
Existing Monthly Volume	2,000/day between months	2,000/day between months	8,000	1,000
Seasonally Adjusted Steady Flow	2,000/day between months	2,000/day between months	> 8,000 varies by month	1,000
Year Round Steady Flow	2,000/day between months	2,000/day between months	prorated annual volume	1,000

For each alternative, the economic and financial impacts on seven large utilities and over 100 small utilities were estimated for both the existing contract rate of delivery (CROD) institution and an optimal institutional arrangement (HYDROLOGY). Under both institutions examined, the total energy produced is the same but there are losses in summer and winter capacity for most alternatives. The loss of capacity has considerable financial and economic impact on the power system. The estimated economic impacts (Stone and Webster 1992, Moulton 1992) are illustrated in Figure 1. These impacts are calculated following the Principles and Guidelines (U.S. Water Resources Council 1983).

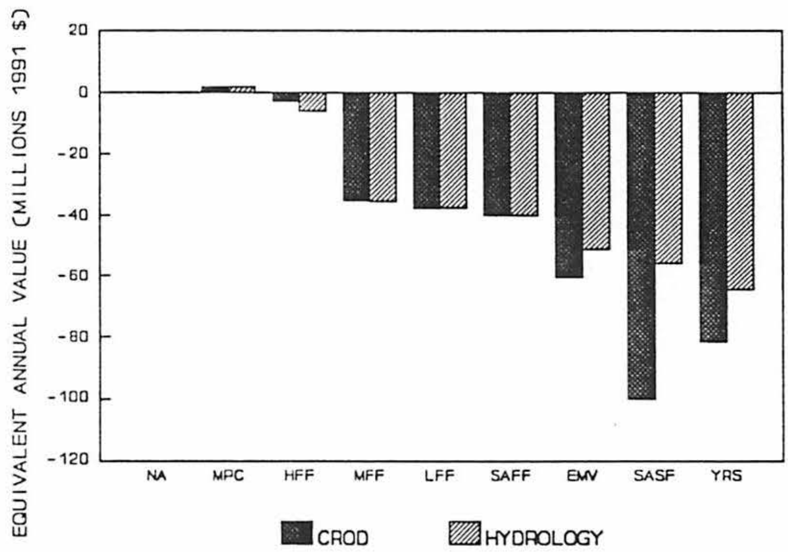

Figure 1. Estimated Economic Impact on Power System.

Restrictions, the specified ramping rates, allowable daily changes in flow, and minimum flows, largely determine the potential generation capacity for any given alternative. As shown in Figure 1, the system-wide economic impact of the alternatives increases with the degree of these operational restrictions. The Seasonally Adjusted Steady Flow alternative has the largest cost since the powerplant is baseloaded and monthly release volumes during peak load months are reduced compared to the No Action Alternative.

As noted in Figure 1, estimates of impact differ between the two institutions examined. Estimates made under the CROD institution represent potential impacts under the existing contractual framework. To the extent that the contractual framework changes, impacts are likely to be less than those portrayed under the CROD institution. Estimates made under the HYDROLOGY institution represent potential impacts if the contractual framework changes and optimal adjustments to the power system are made. To the extent that the contractual framework does not change and optimal adjustments are not made, impacts are likely to be greater than portrayed under the HYDROLOGY institution. Conceptually, these two institutions represent the extremes of likely economic impact.

The impacts displayed in Figure 1 are currently being revised to address several shortcomings. The estimates of economic impact presented here apparently reflect some degree of inter-system transfer payments thereby overstating the economic effect by an unknown amount. These payments will be eliminated in subsequent analyses. In addition, forthcoming analyses will be based on a framework more conducive to the assessment of existing facilities, will model energy conservation measures in a more appropriate manner, and will utilize improved hydrology series. These refinements will allow for a more accurate appraisal of national economic impact. However, the relative economic ranking illustrated in Figure 1 is unlikely to change.

Conclusion

Generation of peaking power at Glen Canyon Dam causes downstream releases to fluctuate on an hourly basis. The resulting variations in flow and river stage may have significant impacts on native and non-native fish, recreational, cultural, and riparian resources. Constraints on hydropower operations may well be imposed to reduce the impacts on these resources. These constraints will degrade demand following capability and decrease the capacity of this facility to generate power on peak. Large and significant economic effects on the power system will result. The magnitude of the estimates presented here argues for a careful assessment of the tradeoff.

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Forthcoming in Water Resources Research

A METHODOLOGY FOR QUANTIFYING AND VALUING THE IMPACTS OF FLOW CHANGES ON A FISHERY

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A METHODOLOGY FOR QUANTIFYING AND VALUING THE IMPACTS OF FLOW CHANGES ON A FISHERY

ABSTRACT

A quasi-population model for adult brown trout was developed for the Taylor River below the Taylor Park Reservoir in Colorado. This model allows the population to be predicted under alternative flow management regimes. The predicted population effects of two different flow release patterns were compared with the predicted population for the current reservoir operation regime. Changes in angler catch were imputed for these scenarios. The changes in catch were valued using estimates of willingness to pay obtained from anglers fishing at the site. Total angling effort was held constant. For both of the flow scenarios examined the difference in economic use value was limited. The relatively small changes in value predicted were shaped by the small changes in catch predicted and the high number of fish caught under current conditions.

A METHODOLOGY FOR QUANTIFYING AND VALUING THE IMPACTS OF FLOW CHANGES ON A FISHERY

Releases from storage reservoirs have traditionally been made for agricultural purposes, mining and manufacturing, municipal water supply, and other off-stream uses. Now however, management strategies which favor these traditional water uses are being questioned and operation regimes which recognize the importance of fisheries, habitat maintenance, and other uses requiring adequate stream flow are being formulated. In Colorado, as in other western states, the question of how to balance reservoir releases between traditional water uses and instream uses such as maintaining recreational fisheries has become the subject of considerable debate.

While there are numerous political, legal, and philosophical aspects to this debate, objective economic analysis hinges on the development of tools for quantifying and valuing the impacts on recreational fisheries which result from changes in flow regimes. At a minimum, these tools must allow for the prediction of fish populations under differing flow regimes, linkage of these fish populations to fish catch, and estimation of the economic value of this catch. The three objectives of this study were; (1) to develop a framework for predicting fish population as a function of stream discharge, (2) to estimate the economic use value of these fish, and, (3) to demonstrate the use of this framework for the analysis of alternative reservoir release regimes.

RELATED STUDIES

While there are numerous examples of aquatic population models in the literature, few of these models explicitly capture the effect of stream flow and lend themselves to the analysis of different flow management regimes. Recently however, two studies based on flow driven models have appeared in the literature.

Cheslak and Jacobson (1990) employed a fisheries population model based on the method used in the present study: the Instream Flow Incremental Methodology (IFIM). Cheslak and Jacobson predicted the flow impacts of a proposed hydroelectric project on fish populations in the Clavey River in California. The results reported by the authors and the population response predicted in this analysis are similar. The Cheslak and Jacobson model is not linked to fish catch or economic value.

Another study by Fisher, Hanemann, and Keeler (1991) is based on a rather sophisticated biological modelling effort and explores the impact of alternative flow management regimes, as well as other choice variables, on the population of salmon in the Sacramento and San Joaqin rivers. The population model described by the authors is both more cost intensive and more comprehensive than that developed here. While the initial stage of their investigation was not linked to economic value, the authors report ongoing work that will allow the costs of alternative water management regimes to be compared with their benefits.

In contrast to flow driven population models, the economics of recreational fishing has been studied rather extensively. For example, Walsh, Johnson, and McKean (1988) cite thirty-one studies on the economics of coldwater fishing. A subset of these studies and several more recent studies have estimated the marginal benefits of fish catch. Studies by Sorg et. al. (1985), Loomis (1986), Cameron and James (1987), Johnson and Walsh (1987, 1989) and Huppert (1989) are examples.

The Johnson and Walsh work is particularly relevant to our effort since they estimated the marginal value of fish caught at sites in Colorado. Johnson and Walsh (1987) used contingent valuation to estimate the value of fish caught at Colorado's Blue Mesa Reservoir, a location downstream from our study site. They reported that the marginal value of a trout or coho salmon caught at the site was approximately $0.95. In a later study of anglers on the Poudre River, Johnson and Walsh (1989) found that the mean catch was 4 fish per angler day and the value of catching an additional fish was approximately $0.78.

A study by Johnson and Adams (1988) is the best example in the literature, to date, of a study which explicitly recognizes the relationship between stream flow, fish population, fish catch and economic use value. The authors estimated a fisheries production model relating the population of steelhead on the John Day River in Oregon to mean quarterly flows, dam construction, and marine productivity. Contingent valuation was used to elicit angler's willingness to pay for improvements in fish catch. Their study is especially laudable for its interdisciplinary approach and treatment of the underlying biological processes.

Our research builds upon the Johnson and Adams work in two important ways. First, the model developed here is driven by mean monthly flows rather than mean quarterly flows and thus allows for a more sophisticated analysis of alternative flow regimes. Second, the model used here is a multiple life stage model which encompasses both critical flow periods and flow "threshold effects" (Johnson and Adams, 1988, page 1842). This approach allows for a more realistic appraisal of population response to flow changes.

CONCEPTUAL OVERVIEW

A quasi-population model, termed the effective habitat model, is used to predict the impacts of changing the timing and quantity of reservoir releases on downstream fish populations. The predicted change in fish population is linked to changes in the number of fish caught by anglers. The predicted change in fish catch is valued using estimates of angler willingness to pay. Two case study applications are presented.

THE EFFECTIVE HABITAT FRAMEWORK

The effective habitat model is an extension of the Instream Flow Incremental Methodology (IFIM), a modelling framework developed by the National Ecology Research Center of the U.S. Fish and Wildlife Service. IFIM is widely used to analyze environmental changes in streams and rivers. In the Physical Habitat Simulation System (PHABSIM) component of IFIM (Milhous, Updike, and Schneider, 1989) physical habitat is defined as a weighted sum, over the stream surface, of the product of suitability indices for depth, velocity, and channel morphology. This measure is calculated for a range of discharges yielding a relationship between physical habitat and stream discharge.

Extension of IFIM to the effective habitat model developed here was originally suggested by Bovee (1982) and later made operational by Waddle (1992). This model is based on the premise that in the highly variable stream environment, flow-determined physical habitat limits the size of the fish population present during the biological year - April through March for the stream system under study. While effective habitat could be calculated for any discrete time step, mean monthly flows were used for consistency with existing hydrological projections.

Four life stages (L) of brown trout are tracked in the model. These are: the spawning and incubation life stage (egg stage), the fry life stage, the juvenile life stage, and the adult life stage. Each life stage is assumed to occupy its available habitat uniformly and at a constant density (η_L) which is calculated from the observed population and the amount of habitat present. For each life stage, the limiting available habitat (LAH) is the minimum of the monthly habitat values that occur during the biological year, or portion thereof, that the life stage is present in the stream.

Life stage (L-1) progresses to life stage (L) using habitat multipliers (M). These multipliers are based on average mortality rates and habitat densities derived for each life stage of the population. Survivors from the previous life stage (L-1) to life stage (L) occupy habitat of type (L) at the average density for that life stage. The habitat area needed to accommodate the (L) individuals is termed habitat demanded (HD). The habitat demanded for life stage (L) in year (y) is calculated using equation (1) and the effective habitat (EHAB) in year (y) is calculated using equation (2). Since each life stage is populated by individuals maturing from a previous life stage, effective habitat (EHAB) is calculated as an ongoing process using both equations (1) and (2).

$$\mathbf{HD}_{L,y} = \mathbf{EHAB}_{L-1,y-1} * \mathbf{M}_{L-1,L} \quad (1)$$

$$\mathbf{EHAB}_{L,y} = \mathbf{MIN}(\ \mathbf{LAH}_{L,y},\ \mathbf{HD}_{L,y}) \quad (2)$$

If the habitat required by the (L) age fish in year (y) exceeds the amount of limiting available habitat, loss of the excess (L) individuals occurs. If the habitat required by the (L) age fish is less than the amount of limiting available habitat, excess habitat is present. When there is excess habitat, the survival of (L) individuals is not limited by the available habitat. The model is calibrated to observed data using mortality rates (Waddle 1990).

As shown in (2), effective habitat (EHAB) is the minimum of the limiting available habitat (LAH) and the habitat demanded (HD) both of which are functions of past flow (F_t, F_{t-1}, F_{t-2}, ... $F_{t-\infty}$), henceforth represented more compactly as $F(\cdot)$. An equivalent reduced form representation of effective habitat is shown on the right-hand side of (3). Since it is assumed that each life stage exists at a uniform and constant population density (η_L) within the defined habitat type, the population of adult fish, the life stage sought by anglers, is proportional to adult effective habitat area as shown in (3).

$$\mathbf{FSTOCK}[F(\cdot)] = \eta * \mathbf{EHAB}[F(\cdot)] \quad (3)$$

The effective habitat model is somewhat mechanistic and is relatively less complex than models described elsewhere (for example, see Fisher, Hanemann, and Keeler 1991). For this reason we describe the model as a quasi-population model. The advantage of this modelling framework is that it reflects the impacts of preceding flow events and imitates the lag structure or memory of the fish population. This behavior facilitates the realistic analysis of alternative flow management regimes by illustrating long-term as well as short-term population effects.

THE ECONOMIC FRAMEWORK

For any angler (i), her catch (C_i) is a function of the standing stock of fish present, which is represented by η*EHAB[F(•)], the amount of fishing effort (E_i) expended, and the skill possessed by the angler (S_i) as shown in (4).

$$C_i = C[\ \eta * EHAB[F(\cdot)],\ E_i,\ S_i\ ] \tag{4}$$

The economic value of catch for angler (i) is reflected by their willingness to pay (WTP_i). An angler's willingness to pay (WTP_i) is a function of catch (C_i), income (I_i), a vector of other socioeconomic factors ($\underline{X}_i$), and an index of site quality (Q) as shown in (5).

$$WTP_i = w(\ C_i,\ I_i,\ \underline{X}_i,\ Q\ ) \tag{5}$$

Aggregating (5) over all anglers, from i = 1 to n, yields a measure of aggregate or total willingness to pay, (WTP). For a discrete change in flow, holding the other arguments (I, E, S, $\underline{X}$, Q) constant, the change in total willingness to pay as flow changes is approximated by (6).

The first term on the right-hand side of equation (6),

$$\frac{\Delta WTP}{\Delta F(\cdot)} = \frac{\Delta WTP}{\Delta C} * \frac{\Delta C}{\Delta(\eta * EHAB)} * \frac{\Delta(\eta * EHAB)}{\Delta F(\cdot)} \tag{6}$$

$\Delta WTP/\Delta C$, is the value of the additional fish caught. This varies with the number of fish caught and is estimated for an individual angler through the use of the dichotomous choice contingent valuation methodology.

The second term on the right-hand side of equation (6), $\Delta C/\Delta(\eta * EHAB)$, is the change in catch as fish population changes. This term is assumed to be a constant, denoted in (7) by Φ.

The third term on the right-hand side of equation (6), $\Delta(\eta * EHAB)/\Delta F(\cdot)$, is the change in fish population as flow changes. Both the value and sign of this term vary with the level of present and past stream flows. The value of this term is estimated by taking the difference between the effective habitat simulated at one flow level and the effective habitat simulated at an alternate flow level.

As estimated in this study, equation (7) describes the change in the use value of a fishery which results from a discrete change in flow regime.

$$\frac{\Delta WTP}{\Delta F(\cdot)} = \frac{\Delta WTP}{\Delta C} * \Phi * \frac{\Delta(\eta * EHAB)}{\Delta F(\cdot)} \tag{7}$$

ESTIMATION OF WILLINGNESS TO PAY

The dichotomous choice contingent valuation methodology was used to estimate angler's willingness to pay for catch.

This approach is characterized by the use of yes/no (dichotomous) questions for eliciting willingness to pay. This technique and it's underlying random utility foundation are discussed extensively in the current literature (Hanemann 1984, Cameron and James 1987, Cameron 1988, and McConnell 1990).

In this application, four dichotomous choice willingness to pay questions were posed to each respondent. Respondents were first asked to record their average catch. Then they were asked to indicate willingness to pay for this level of catch, and for hypothetical additions to their average catch of 1 fish, 3 fish, and 7 fish of average size respectively. Willingness to pay questions (Appendix 1) were phrased in terms of making an additional yearly payment to support improved management practices. The survey instrument also included questions about the respondent's fishing trip, the number of days they fished, their fishing method, and questions about the respondent's age, education, income and other socioeconomic factors.

Dichotomous choice surveys present three important design considerations: the identification of an appropriate bid range, distribution of bids, and selection of the sample size. Duffield and Patterson (1991) have proposed a promising methodology for use in the single regressor case. However, no definitive methodology for multiple regressors has yet emerged and the establishment of an appropriate sample size, efficient bid range, and allocation of bids remains very much an art.

In this study twenty bid series were constructed. Each series consisted of bids for the base case and for 1, 3, and 7 fish improvements in catch. Base case bids ranged from \$0.10 to \$65.00, bids for the 1, 3, and 7 fish improvements ranged from \$0.75 to \$80.00, \$2.00 to \$95.00, and \$3.00 to \$150.00, respectively. Within each series bids increased as catch improved. Bid series were assigned uniformly and randomly to the surveys.

Respondent's willingness to pay was assumed to be continuous and non-negative. The logit model, based on the cumulative logistic density function, was assumed to describe the probability that an individual would respond "yes" to a given bid. In the logit model, the probability of obtaining a "yes" response (P) is specified as (8):

$$P = \frac{1}{1 + \exp(-BW)} \tag{8}$$

where: P = probability of a "yes" response;

B = a vector of coefficients;

W = a vector of explanatory variables which includes price (V)

Integrating expression (8) with respect to price (V), from 0 to T, yields mean willingness to pay (WTP_i) as shown in equation (9).

$$WTP_i = \int_{V=0}^{T} \frac{1}{1+\exp(-BW)} dV \tag{9}$$

A number of parameters have been proposed to describe the estimated distribution of willingness to pay. Among these are: the median (where in (8), $P = 0.5$), the expected value (where in (9), $T = \infty$), the truncated mean (where in (9), $T = V^* < \infty$), and various percentiles of the distribution (Hanemann 1984, 1989). In a manner consistent with other recent studies (Duffield and Patterson 1991, Park, Loomis, and Creel 1991) the truncated mean was used in this study to describe the distribution of willingness to pay.

THE STUDY SITE

This study was conducted on the Taylor River which is located approximately 210 miles southwest of Denver, Colorado. The hydrology of the Taylor River is characterized by low winter flows with extreme high flows occurring during the spring runoff period. Flows in the lower Taylor River are controlled by releases from Taylor Park Reservoir which has a live storage capacity of 106,200 acre feet.

The fishery in the Taylor River is composed of both Brown trout, Salmo trutta, and Rainbow trout, Oncorhynchus mykiss. The focus of this analysis is on brown trout which have established a naturally sustaining population and are present at relatively high densities. This population is apparently limited by two factors; (1) low winter flows which reduce the amount of available habitat, and, (2) high spring flows which periodically cause the loss of newly hatched fry (Bovee 1988).

THE RESULTS

The Effective Habitat Model

The biological data used in this study were collected by the Colorado Division of Wildlife in October of 1979, 1980, 1981, 1982, and again in 1984. Electroshocking was employed to sample the fish population. The size of the population and its age structure were then estimated. Physical and hydrologic data used in the habitat model were collected by Barry Nehring of the Colorado Division of Wildlife in 1984.

Using the data collected by Nehring and the habitat suitability index curves found in Raleigh, Zukerman and Nelson (1986), physical habitat versus flow relationships for the four life stages of brown trout were estimated. The relationship for adult brown trout in the Taylor River is illustrated in Figure 1. Apparently, adult habitat is not a monotonically increasing function of flow. Instead, adult habitat per linear foot of stream channel rises as flow increases, reaches a peak at approximately 325 cubic feet per second (cfs), and then falls as flow increases further.

Work by Bovee (1988) provides evidence that high flows are deleterious to sub-adult life stages. However, some authors have questioned the decline in adult habitat at high flows which is simulated by the PHABSIM model. In fact, Cheslak and Jacobson (1990) note that the magnitude of this result is "counterintuitive". This aspect of model behavior is conditioned on the use of the Raleigh, Zukerman, and Nelson (1986) habitat suitability curves. These curves were used both in this study and in the Cheslak and Jacobson study and largely shape the findings of both studies.

Using the methodology described previously and further detailed in Harpman (1990), the biological data, the physical data, and a time series of monthly stream discharge were employed to construct an effective habitat model for the Taylor River from the Taylor Park Reservoir to its confluence with the East River. The model was calibrated to observed data using mortality rates. When calibrated, adult brown trout were predicted to exist at a density (η) of 0.061 adults per square foot of adult effective habitat.

[Figure 1 goes here]

Economic Valuation

During the summer of 1989, survey enumerators contacted 289 anglers on the Lower Taylor River and at adjacent public fishing sites on the Upper Gunnison River. During this contact the enumerators briefly explained the purpose of the survey to anglers and asked them to participate. Of the 289 anglers contacted, 287 (99%) agreed. Their names, addresses, telephone numbers, and contact location were recorded. A mail survey was then sent to these anglers in October of 1989. Mailings, reminders, and follow-up mailings followed the methodology described in Dillman (1978). Adjusted for undeliverable surveys the return rate was approximately 84.0% (237). Perhaps due to institution of a substantially higher fee structure for fishing licenses, a number of protest responses were received. In addition, responses from individuals who did not complete all of the valuation questions were deleted. Following these adjustments 153 observations were available for analysis.

Using the survey data, the probability of obtaining a **yes** response was estimated using maximum likelihood techniques for a variety of functional forms and specifications. Based on the value of the chi-squared goodness of fit test, the log-logistic model was chosen, where in (8), the vector **W** is replaced by the natural log of the vector **W**. The results shown in (10) were obtained:

$$\mathrm{LOG}\left[\frac{P}{1-P}\right] = \underset{(3.67)}{4.69} - \underset{(-9.93)}{0.934}\ \mathrm{LPRICE} + \underset{(2.21)}{0.161}\ \mathrm{LCAT}$$

$$\underset{(-3.38)}{-1.038}\ \mathrm{LAGE} + \underset{(3.82)}{0.516}\ \mathrm{LINC} + e_i \qquad (10)$$

Maddala R^2 = .24 percent of correct predictions = 72%

where: P = probability of a yes (1) response

LPRICE = natural logarithm of price

LCAT = natural logarithm of total catch per day

LAGE = natural logarithm of the respondent's age

LINC = natural logarithm of family income (1000's)

( ) = the values in parentheses are asymptotic t-statistics

e_i = random disturbance term

The coefficients for LPRICE, LINC, LAGE, and the constant term are statistically significant at the 99% level of confidence. The natural logarithm of total catch per day, LCAT, is significant at the 95% level of confidence. Maddala's R^2, one measure of goodness of fit (Maddala 1983, equation 2.49), indicates that the equation is relatively robust. The percentage of individuals whose response is correctly predicted is approximately 72%. There was no significant difference between the responses obtained from anglers contacted on the Taylor River and those contacted on the Upper Gunnison River.

Numerically integrating the estimated relationship (10) from zero to the truncation price level, T, yields mean willingness to pay. The estimated area was truncated at the 90th percentile of the distribution and was normalized as discussed in Boyle, Welsh, and Bishop (1988). While this adjustment does not eliminate the potential underestimation problem, it does make the estimated cumulative density function consistent with the level of truncation (Park, Loomis, and Creel 1991).

With the other variables held constant at their sample means, integrating relationship (10) at different levels of total catch per day yields mean willingness to pay at each catch level. These estimates, adjusted for the average number of days fished in the study reach, are reported in Table 1. The difference between mean willingness to pay, estimated at two different levels of catch, is the marginal value of a fish caught. As shown, the value of an additional fish is high for small numbers of fish caught and low for large numbers of fish caught. The mean catch reported by anglers in the study area is approximately 7 fish per day. The value of a one fish increase in the average number of fish caught per day (from 7 to 8) is $0.46 per angler. At the same level of average catch, the estimated values are consistent with those reported by Johnson and Walsh (1987, 1989).

As demonstrated by Johnson and Walsh (1989), angler skill and reported catch may be closely related. Practical difficulties associated with recognizing and quantifying angler skill precluded development of a satisfactory skill variable for use here. An alternate approach, estimating willingness to pay using only changes in catch, is intractable with the log-logistic formulation. As a result the independent contribution of skill to angler catch is not determined in (10).

[Table 1 goes here]

The methodology described in Park, Loomis, and Creel (1991) was used to estimate a 95% confidence interval for mean willingness to pay. At the point of sample means, corresponding to a catch of seven fish in Table 1, the 95% confidence interval for mean willingness to pay is from $23.80 to $34.59.

MODELLING HABITAT AND POPULATION IMPACTS

In the next section two case study applications are examined. In the first, the impacts of moving from one reservoir operation regime to a new release regime are quantified and valued. In the second case study the downstream impacts of a proposed water development project are explored.

Case 1: A Change in Reservoir Operation Regime

Taylor Park Reservoir was constructed in 1937 to supply irrigation water to the Uncompahgre Valley Water Users Association. Prior to 1975, the reservoir was operated in a "fill and spill" fashion henceforth referred to as the "pre-

1975 operation regime." Under this regime, inflows from the Taylor River were stored until reservoir capacity was reached and the remaining inflows were passed over the spillway. Water was released for irrigation as needed during the growing season and the reservoir was evacuated in the late fall. Little water was released during other periods and the recorded flow in the Taylor River reached zero on a number of occasions. Under this release regime the quality of the fishery declined substantially.

Blue Mesa Reservoir was constructed on the Gunnison River below the Taylor Park Reservoir in 1966. The capacity and downstream location of Blue Mesa Reservoir allowed for the re-regulation and storage of releases from Taylor Park Reservoir. In 1975 the Uncompahgre Water Users Association signed an agreement with the U.S. Bureau of Reclamation establishing a system of storage credits and facilitating a change in releases to "... optimize fishery conditions in and below the reservoir area" (U.S. Department of the Interior 1975). The current reservoir operation regime was established as a result of this agreement and is referred to hereafter as the "current operation regime."

Using measured flows from the U.S. Geological Survey gauge and natural flows developed for the Colorado River Simulation System (U.S. Department of the Interior 1987) a simple mass balance model of pre-1975 reservoir operations was constructed. Using this mass balance model mean monthly flows for the period 1975 to 1987 were simulated. These flows were then used to develop simulated pre-1975 flows for the study site at Almont. Simulated pre-1975 flows and measured flows (current operation regime) at Almont were, in turn, used to drive the effective habitat model. The results obtained are compared in Figure 2.

As shown in Figure 2 the predicted population of adult brown trout under the pre-1975 operation regime is unambiguously less than the predicted population under the current operation regime. The difference is due to two effects. First, minimum flows during the critical winter months are higher under the current operation regime than under the simulated pre-1975 flow regime. This supports a higher adult population from year to year. Second, current operations have reduced flow fluctuations in the fall and winter and this has improved spawning success and increased recruitment. The predicted improvement is supported by field observations which indicate that the population of brown trout increased significantly following institution of the current flow regime (Nehring 1988).

[Figure 2 goes here]

Case 2: A Water Development Project

Three major water development projects have been proposed within the Upper Gunnison Basin. One of these projects is the Collegiate Range Project Alternative I. As the project is envisioned, approximately 60,000 acre feet of water annually would be pumped from a site above the Taylor Park Reservoir through the Collegiate Mountain Range to the eastern slope. Since the purpose of the Collegiate Range Project is to export water from the basin, flows in the Taylor River would be reduced by the amount of water exported.

To examine the impacts of this proposed project on the downstream fishery, measured flows (current operation regime) and with-project flows (ENARTECH Inc. 1989, Table 6.6, page 52) were used to drive the effective habitat model. The results of this analysis are also shown in Figure 2.

As shown in Figure 2, the predicted with-project population of adult brown trout is considerably lower in low runoff years than it would have been without the project. This is particularly evident in the 1976 - 1979 period. Apparently, export of water out of the basin would cause a decline in the habitat available. In high runoff years, the predicted with-project population is slightly higher than the population predicted for the current operation regime. Evidently, the proposed project would buffer, to some degree, the high peak flows which are common in the spring. This produces a greater brown trout population during those years (refer to Figure 1). Given the with-project operation rule and the resulting flows, these two conflicting effects are predicted to produce a relatively small and negative effect on the brown trout population.

MEASURING THE ECONOMIC EFFECTS

The economic impact of the change in brown trout population arising from differing flow regimes is dependent on the resulting change in angler catch. As discussed previously, angler catch is related to fish population by the catch multiplier, Φ. While it was initially presumed that the value of Φ must lie between 0.0 and 1.0, the magnitude of this parameter proved to be a more interesting empirical question than originally envisioned. For example, Behnke (1987) cites instances where the average value of Φ ranges from 2.0 to nearly 3.0 in cases where angling effort was between 400 to 3,800 hours per surface acre and the trout species sought were relatively vulnerable to angling pressure.

By comparison, fishing effort on the Taylor River is relatively low per unit area and brown trout are less vulnerable to fishing pressure than are many other trout species. The most recent creel census in the study area was conducted during the summer of 1982 (Colorado Water Resources and Power Development Authority 1988, pages 7-15). At that time it was estimated that there were 8,100 angler days of effort annually on the Taylor River below the Taylor Park Reservoir. This represents approximately 100 hours of effort per surface acre. Anglers reportedly caught 9,761 brown trout (Nehring 1983) while the remainder of their bag was composed primarily of stocked rainbow trout. The predicted population of adult brown trout in 1982 is 105,692 fish.

These data allow the calculation of an average value for Φ but not a marginal value. Consequently, the catch multiplier Φ is assumed to be approximated by this average value (0.092) and is invariant over the range examined. Using Φ, the predicted change in angler catch is readily imputed from the predicted change in adult trout population. The change in the number of fish caught by anglers can then be valued using the marginal values found in Table 1.

Two further assumptions are necessary in order to complete the economic analysis. First, it is assumed that there are 8,100 angler days of effort in this reach annually and that fishing effort does not change as catch changes. It is also assumed that any change in catch is uniformly distributed. Given these assumptions, if a decline in fish catch were to occur, the first 8,100 fish loss in catch is valued at $0.61 per fish (a change in average catch from 7 to 6 for each of the 8,100 anglers days). If the reduction in catch is greater than 8,100 fish, the remainder is evaluated at the appropriate marginal rate(s). For example, the increment in catch between 8,100 and 16,200 fish (a change in average catch from 6 to 5 for each of the affected anglers) would be valued at $0.73/fish. Summing the change in value for each increment yields an estimate of the total change in use value.

Using the approach described and compounding the thirteen year series of values at a 6% rate of interest, the benefit of moving from the pre-1975 reservoir operation regime to the current operation regime is $43,448 in 1987 dollars. Similarly, moving from the current flow regime to the with-project flow regime results in a loss of $12,222 in benefits.

The rather limited economic effects predicted for the two cases examined are shaped by several factors. The most important factor is the resistance of brown trout to angling pressure. This is reflected by the value of the catch multiplier which suggests that approximately 9% of the adult brown trout population will be caught by anglers. As a result, even large changes in fish populations will have a relatively small effect on angler catch. Placed in perspective, the predicted increase in catch for the first case examined was approximately 0.50 fish per angler day and in the second case the predicted decrease in catch was approximately 0.10 fish per angler day. Since the average catch reported by anglers was seven fish per day, the value of a small change in catch is relatively low.

Admittedly, the economic impacts presented here reflect only the value of the predicted change in catch. If anglers respond to changes in catch by altering their fishing effort these estimates may understate long-run changes in the economic value of the fishery. However, the size of the predicted changes in catch for both of the scenarios examined is relatively small. Given some variance in catch, it seems unlikely that anglers would recognize such small differences and adjust their angling effort.

SOME QUALIFICATIONS

The estimated impacts described here are shaped by the assumptions made, the values of the parameters used, and estimates of the marginal value of catch. Sensitivity experiments, which can be obtained from the authors, indicate that the analysis presented is sensitive to the magnitude of the catch multiplier, Φ, and to the magnitude of the adult population density parameter, η. Although the analysis presented here is relatively insensitive to the marginal value of catch, work by Johnson and Walsh (1989) suggests that anglers value wild trout more than hatchery reared trout. The estimates of marginal value used for this analysis are for a weighted average of both stocked and wild fish and should be considered lower bound estimates of the value of catching a wild fish.

CONCLUSION

The purpose of this study was to develop and apply a methodology for estimating fish populations as a function of discharge, to predict changes in fish stocks as flow regimes change, and to quantify the economic value of these changes. A quasi-population model of the lower Taylor River was used to predict the population of brown trout for the current reservoir operation regime, the pre-1975 operation regime, and for one possible with-project flow regime. Angler catch was imputed for each case. The difference in catch between the current operation regime and the two scenarios examined was then valued using the estimated willingness to pay of anglers fishing at the site.

Since reported angler success in the study area was high, the value of the marginal fish caught was relatively low. Further, the predicted change in catch between the current operation regime and the two flow scenarios examined was relatively small. As a result, the estimated impact on the economic value of the fishery was limited. This result is necessarily related to the magnitude and sequence of flows, the values of the parameters employed, the species examined, and the physical characteristics of the study site and may not be representative of the range of impacts expected at other sites. It should also be noted that the estimates of economic impact presented here are based only on a change in use value for a single use in a finite reach of the river system. No attempt was made in this analysis to estimate the impact on other uses, to estimate cumulative impacts, or to estimate the change in nonuse value, if any, which might result from changing the flow regime.

In an earlier article, Ward (1987, p. 383) concluded that, "... important work linking the time path of both stream flows and the resulting catchable fish density needs to be conducted". We concur with this assessment and note that much more research will be needed to produce a rigorous understanding of the complex relationship between flow, fish population, fish catch, and economic value. We hope that our research has contributed to this goal and will help to stimulate future work on this subject.

APPENDIX 1

Assume that, on the average, each time you fished in a stream or river in the Upper Gunnison Basin you would catch **1** additional fish of average size.

Increases in the average number of fish caught, such as that described above, will require changes in the way that the Basin's streams and rivers are managed. Some costs will be involved. If this cost were shared in a fair and equitable manner between all in-state and out-of-state users and all households in Colorado, your share of the cost would be _____ per year.

Would you be willing to pay the amount stated above each year to increase the average number of fish you caught per day in Upper Gunnison Basin Streams by **1** fish of average size? (circle one number)

1. yes, I would pay this additional amount.
2. no, I would not pay this additional amount.

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CAPTIONS FOR FIGURES

Figure 1. The relationship between flow and adult brown trout habitat for the Taylor River at Almont. As shown, habitat increases as flow increases, reaches a maximum at approximately 325 cfs, and then declines as flow increases further. Two different flows may produce the same amount of habitat.

Figure 2. The predicted population of adult brown trout for the three flow regimes examined.

Table 1

INDIVIDUAL WILLINGNESS TO PAY PER DAY

FOR CATCH BY STREAM ANGLERS

Fish Caught	Mean Value ($)	Marginal Value ($/fish)
1	23.06	NA
2	25.05	1.98
3	26.28	1.23
4	27.19	0.91
5	27.92	0.73
6	28.53	0.61
7	29.05	0.52
8	29.51	0.46
9	29.92	0.41
10	30.29	0.37
11	30.63	0.34
12	30.95	0.31

Figure 1

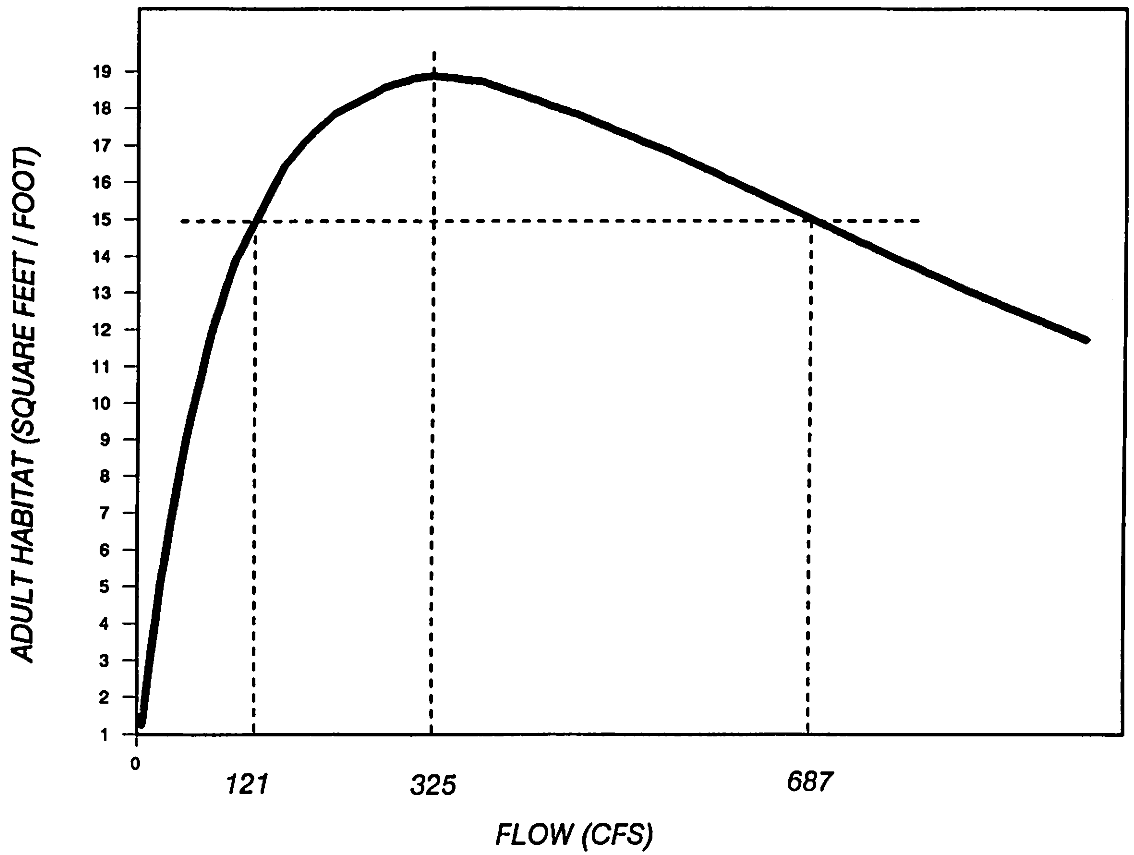
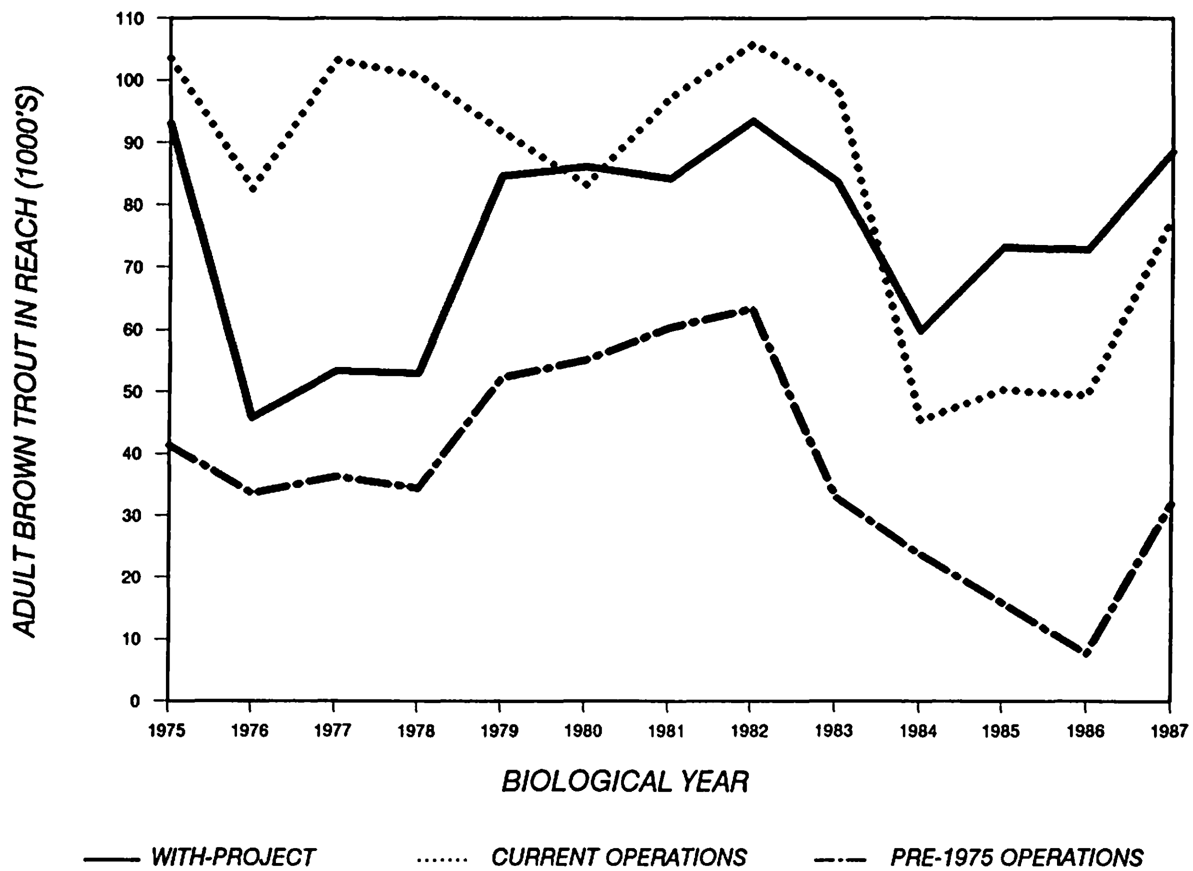

ADULT HABITAT (SQUARE FEET / FOOT)
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
0
121
325
687
FLOW (CFS)

Figure 2



ADULT BROWN TROUT IN REACH (1000'S)
110
100
90
80
70
60
50
40
30
20
10
0
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
BIOLOGICAL YEAR
WITH-PROJECT
CURRENT OPERATIONS
PRE-1975 OPERATIONS