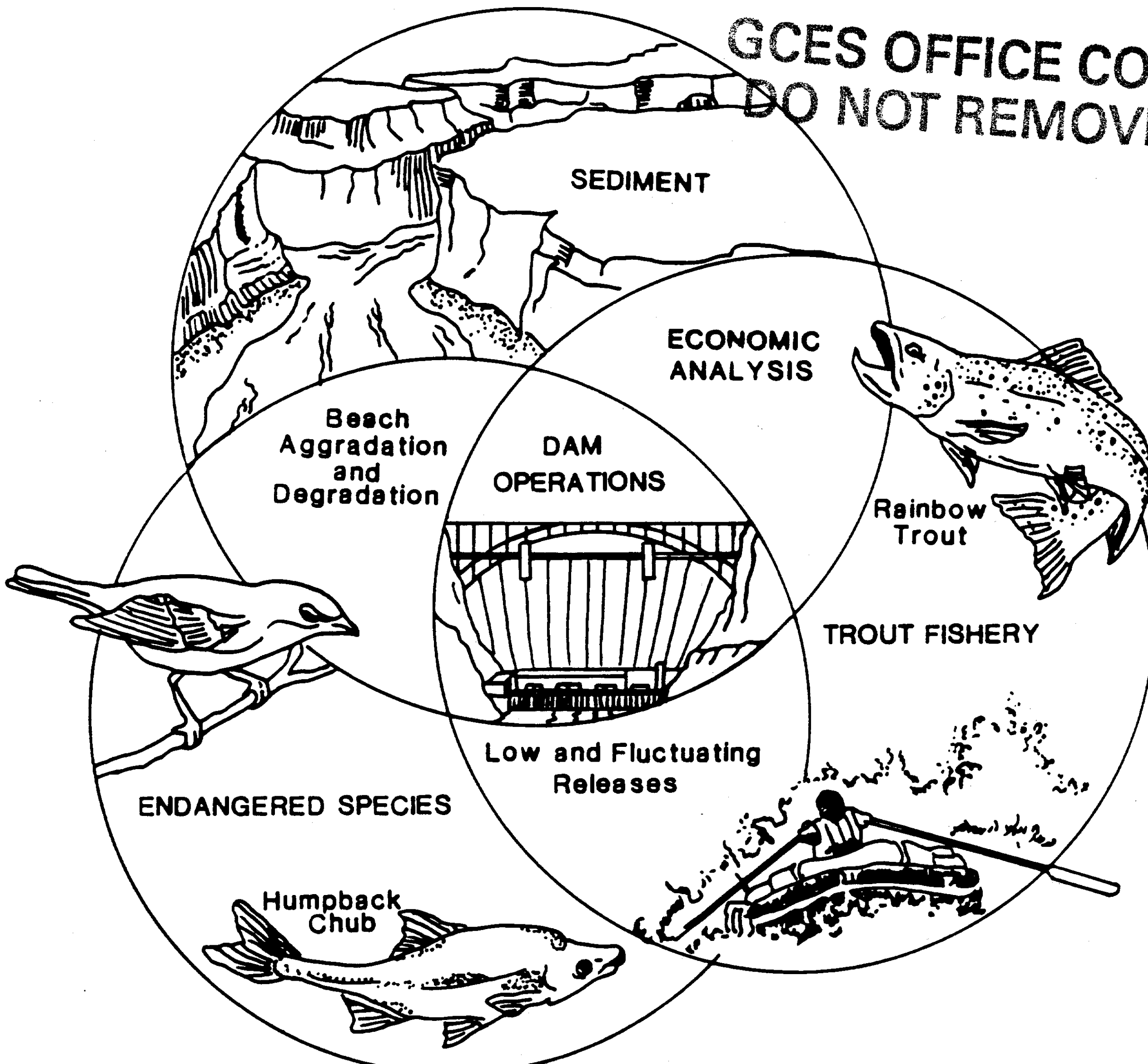
GLEN CANYON DAM

MONITORING OF INTERIM OPERATING CRITERIA



MAY - SEPTEMBER 1992

BUREAU OF RECLAMATIION

GLEN CANYON DAM

MONITORING OF INTERIM OPERATING CRITERIA

May through September 1992

Bureau of Reclamation

This document summarizes the monitoring of Interim Operating Criteria for Glen Canyon Dam for May through September 1992. This is the third report of monitoring of operations, with the first report covering August through December 1991 and the second report covering January through April 1992. Summaries will be published periodically throughout the interim operation period.

BACKGROUND

The Glen Canyon Dam Interim Operating Criteria were implemented on November 1, 1991, following a 3-month testing of the proposed interim flow criteria. An Environmental Assessment was completed in October 1991 with a Finding of No Significant Impact. The Interim Operating Criteria will remain in effect until completion of the Glen Canyon Dam Environmental Impact Statement (GCDEIS) and Record of Decision (ROD). The GCDEIS is scheduled for completion in October 1994 and the ROD shortly thereafter.

Exception Criteria. The Western Area Power Administration and the Bureau of Reclamation signed an interagency agreement on October 21, 1991, which implemented exception criteria and associated interim operating criteria, including financial exception criteria.

Exception criteria allow deviation from the interim flow criteria for response to power system disturbances or other emergency situations and for power system regulation. The agreement incorporates the emergency and system regulation provisions which were in place during research flows and, in addition, includes "financial criteria" as a means of avoiding the expense of purchasing replacement firm capacity and energy during the interim period. The financial criteria element is conditional and the primary conditions include:

- limiting the use of financial criteria to not more than 3 percent of the time (22 hours) in any consecutive 30-day period
- periodic review and renewal
- reporting the use and costs associated with the financial criteria

MONITORING OF INTERIM FLOWS - May through September 1992

MONITORING OF INTERIM FLOW CRITERIA

The operating criteria parameters are: maximum daily flows, minimum daily flows, daily fluctuation, and ramp rates. Parameters are monitored at the Glen Canyon Dam using Reclamation's Supervisory Control and Data Acquisition (SCADA) system. The discharge and river stage changes are monitored at downstream gaging stations near Lees Ferry and Grand Canyon Village. The SCADA data at Glen Canyon Dam is recorded in megawatts of energy and require conversion to flow--cubic feet per second (cfs).

From May 1 through September 31, the maximum flow of 20,000 cfs was adhered to except for a short duration on August 21, due to a system emergency caused by a forest fire (see Attachment A). The minimum flow of 5,000 cfs at night and 8,000 cfs between 7 am and 7 pm were met throughout the period.

Ramping Rates - The ramping rates were exceeded periodically as a result of system disturbances and regulation responses to power demands. Ramping rates may be exceeded under the criteria for system disturbances, regulation, and other emergency situations to allow for power system operation adjustments. The number of times ramping rates were exceeded has been consistently reduced as operators have become more experienced with projecting power system adjustments.

Attachment B shows the traces of discharge and river stages for the Lees Ferry and Grand Canyon gaging stations for May through September 1992.

MONITORING OF EXCEPTION CRITERIA

The exception criteria are monitored at Glen Canyon Dam using Reclamation's Supervisory Control and Data Acquisition System. Several ramping rate deviations from the interim flow criteria occurred, primarily due to electrical system regulation caused by electrical transmission system and generation capability. None of the criteria deviations lasted longer than 1 hour (see Attachment B).

Deviations from the ramp rate criteria generally occur when Glen Canyon Dam is following the power load under system regulation and generally occurs during the upramp. Such deviations are allowed under the generator regulation exception criteria.

To date, financial exception criteria have not been used.

INTERIM FLOW MONITORING PROGRAM - RESOURCES AND RESPONSES

The program focuses on the evaluation of critical resources and ecosystem processes relative to the interim flow regime to determine natural changes in the ecosystem, changes as a result of interim flows, and effects on power generation.

The critical interim flow monitoring programs have been implemented. This monitoring program has been integrated with the ongoing Glen Canyon Environmental Studies (GCES) Phase II research program. The Native American monitoring programs have been initiated concurrent with the other efforts. The interim flow monitoring results will be integrated into the long term monitoring program.

The wet year and summer monsoons have complicated the evaluation of the interim flows. Increased runoff from the Paria and Little Colorado Rivers and side canyon drainages have added sediment and organic matter to the system.

Many of the ecosystem responses are more long-term than short-term; however, qualitative assessments are being conducted on critical ecological elements and processes and to ascertain change. A Scientific Information Management system and Geographic Information System are being developed as tools to assist in the consolidation of data and assessment of specific resource responses. The GCES office, in consultation with the National Park Service, is coordinating the development of both of these elements. All of the information will be utilized in the Long-Term Monitoring Program.

Resource Response. Resources included in the monitoring program and responses to interim flows to date are:

Sediment - During the past three months, water releases from Glen Canyon Dam have been scheduled to meet the January 1, 1993, target elevation for Lake Powell and to meet the downstream water delivery requirements. Releases have ranged from 549,000 acre feet per month to 640,000 acre feet with mean flows ranging from 8800 cfs to 12,000 cfs per month. There has been an increase in the sediment in the main channel of the Colorado River, especially in the area immediately below the Little Colorado River. Sand is building in the main channel and continues to be transported downstream. The sediment deposits (beaches) appear to be stabilizing in this reach along with the backwaters. Erosion is a natural process within the canyon, and beach loss and rebuilding is a normal and important element. Delineating between the natural erosion rates and those modified by interim flow operations is the objective of the interim flow monitoring program.

Riparian Ecosystem - The number of small fluvial marshes along the river corridor has shown an increase, especially in backwater areas at the 20,000 cfs level, providing habitat for insects, birds, and small mammals. The longevity of the marshes is being assessed as the upper ends of the marshes silt in.

Aquatic Ecosystem - Juvenile chub from 1991 are showing up in the mainstem river below the Little Colorado River. During 1992 the Little Colorado River has flooded repeatedly as a result of local precipitation during what has turned out to be a very wet year in Arizona. There is little direct evidence to suggest that 1992 was a very good spawn. The factors that contributed to the reduced spawn are related to local flooding events in the Little Colorado River drainage and the timing of the spawning period.

Natural spawning of trout has also apparently benefitted from the interim operations. This is due to maintaining water over the spawing bars and in the near shore habitat areas. Significant numbers of unstocked fry and fingerling fish have been observed during the Lees Ferry sampling activities by the Arizona Game and Fish Department and GCES.

Cladophora and *gammarus* (foodbase for the trout population) are reestablishing in areas throughout the Lees Ferry reach to pre-research flow levels. Blue green algae species have begun to be established in selected locations in the Canyon and in the Lee's Ferry areas. Blue green algae do not support the extensive diatom food base that the green algae, Cladophora, does.

Endangered Species - The interim flows have been designed to reduce fluctuating levels to enhance and maintain backwaters, side channels, and channel margin habitats. Interim flows have not been in effect long enough to document specific impacts, but monitoring continues.

Cultural Resources - These resources, including Spencer Steamboat above Lees Ferry and Native American sites, are being monitored. The interim flows are designed to reduce sediment erosion and therefore reduce erosion-related impacts to cultural resource sites. Continuous evaluations of the most sensitive locations are planned. Ethnohistorical studies are ongoing for four of the major tribal groups.

Economic Resources - The past three months have had limited power emergencies. Much of the Western power grid has been at full operating level all summer and fall, resulting in substantial capacity and energy being available on the market and reducing strain on the Glen Canyon Dam electrical contractors.

Recreation - Reduced fluctuations and higher minimum flows under the interim flows have provided safer passage for river trips through the Grand Canyon. Access to the Lee's Ferry fishing area has been adequate due to the higher minimum flow releases from Glen Canyon Dam.

Attachments

Attachment A - Glen Canyon Dam Releases
- Integrated Hourly Values - May 1992
- Hourly Ramping Rates (cfs/hour) - May 1992

- Integrated Hourly Values - June 1992
- Hourly Ramping Rates (cfs/hour) - June 1992

- Integrated Hourly Values - July 1992
- Hourly Ramping Rates (cfs/hour) - July 1992

- Integrated Hourly Values - August 1992
- Hourly Ramping Rates (CFS/Hour) - August 1992

- Integrated Hourly Values - September 1992
- Hourly Ramping Rates (cfs/hour) -September 1992

Attachment B - Gaging Stations
- Lees Ferry - Flow Rate - May 1992
- Lees Ferry - Gage Height - May 1992
- Near Grand Canyon Village - Flow Rate - May 1992
- Near Grand Canyon Village - Gage Height - May 1992

- Lees Ferry - Flow Rate - June 1992
- Lees Ferry - Gage Height - June 1992
- Near Grand Canyon Village - Flow Rate - June 1992
- Near Grand Canyon Village - Gage Height - June 1992

- Lees Ferry - Flow Rate - July 1992
- Lees Ferry - Gage Height - July 1992
- Near Grand Canyon Village - Flow Rate - July 1992
- Near Grand Canyon Village - Gage Height - July 1992

- Lees Ferry - Flow Rate - August 1992
- Lees Ferry - Gage Height - August 1992
- Near Grand Canyon Village - Flow Rate - August 1992
- Near Grand Canyon Village - Gage Height - August 1992

- Lees Ferry - Flow Rate - September 1992
- Lees Ferry - Gage Height - September 1992
- Near Grand Canyon Village - Flow Rate - September 1992
- Near Grand Canyon Village - Gage Height - September 1992

Attachment C - Glen Canyon Dam Interim Operations - Western Area Power Administration - May
- Glen Canyon Dam Interim Operations - Western Area Power Administration - June and September 1992

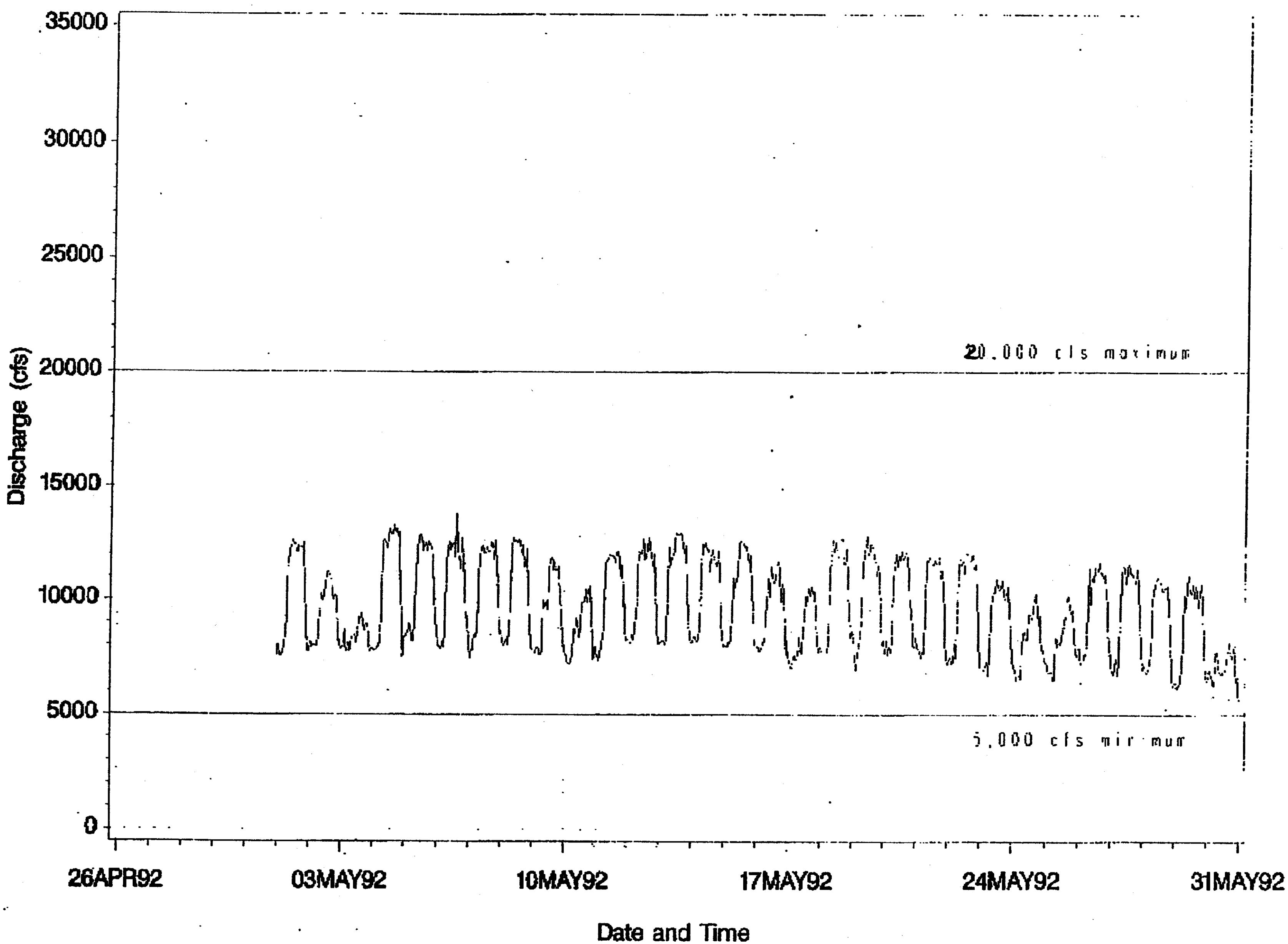
Attachment A

Glen Canyon Dam Releases

Glen Canyon Dam Releases

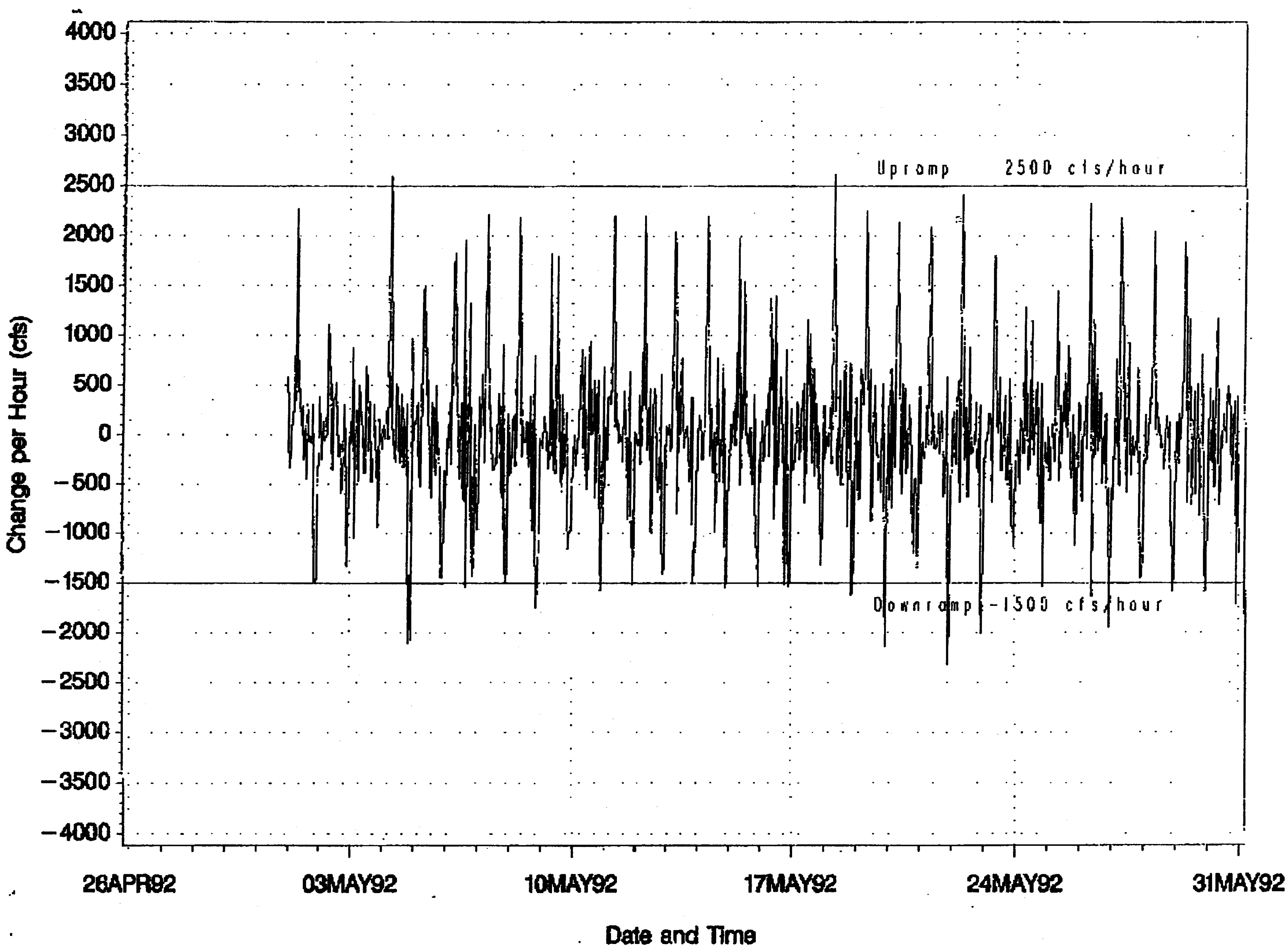
Glen Canyon Dam Releases

Integrated Hourly Values — May 92



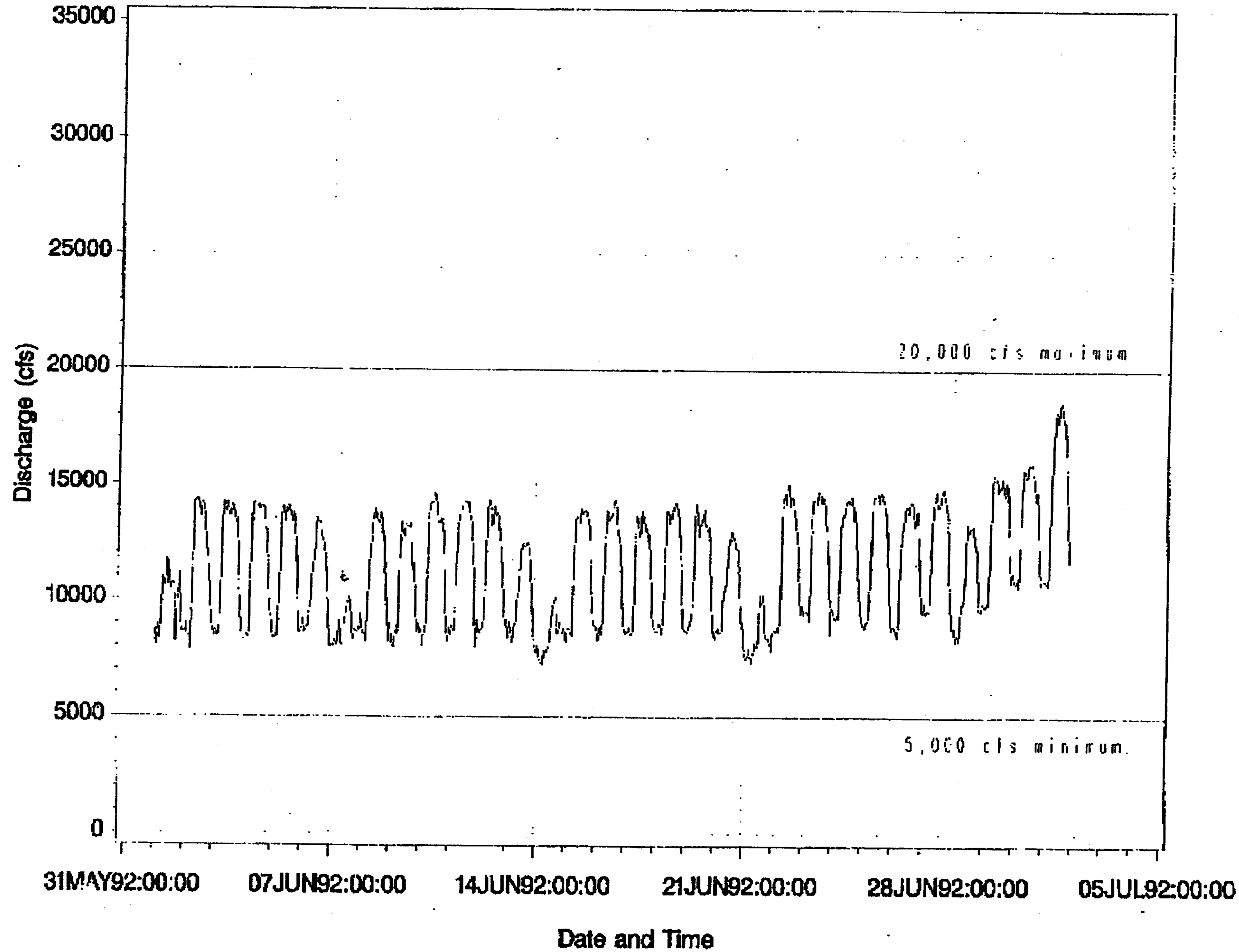
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) — May 1992



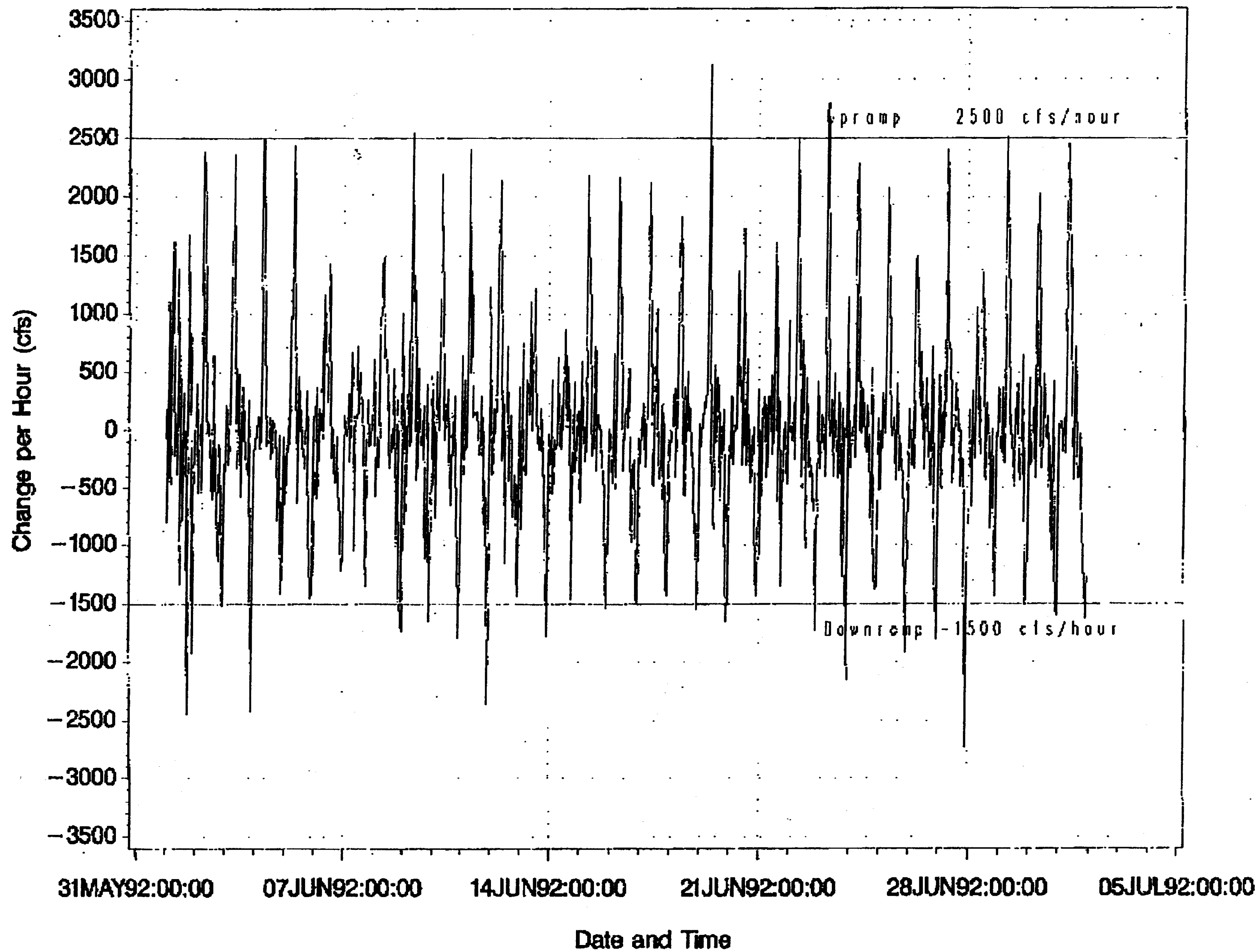
Glen Canyon Dam Releases

Integrated Hourly Values – June 92



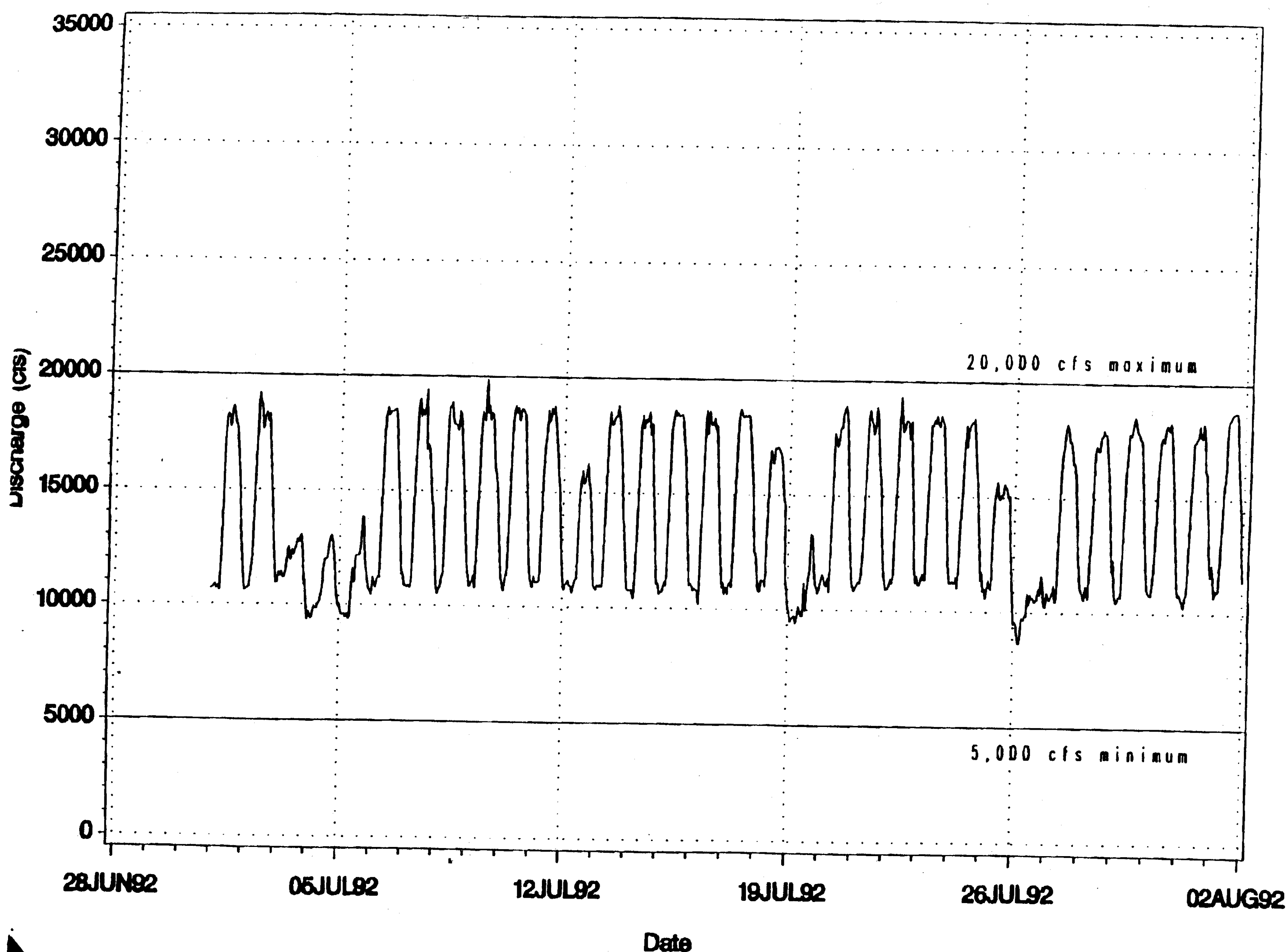
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – June 1992



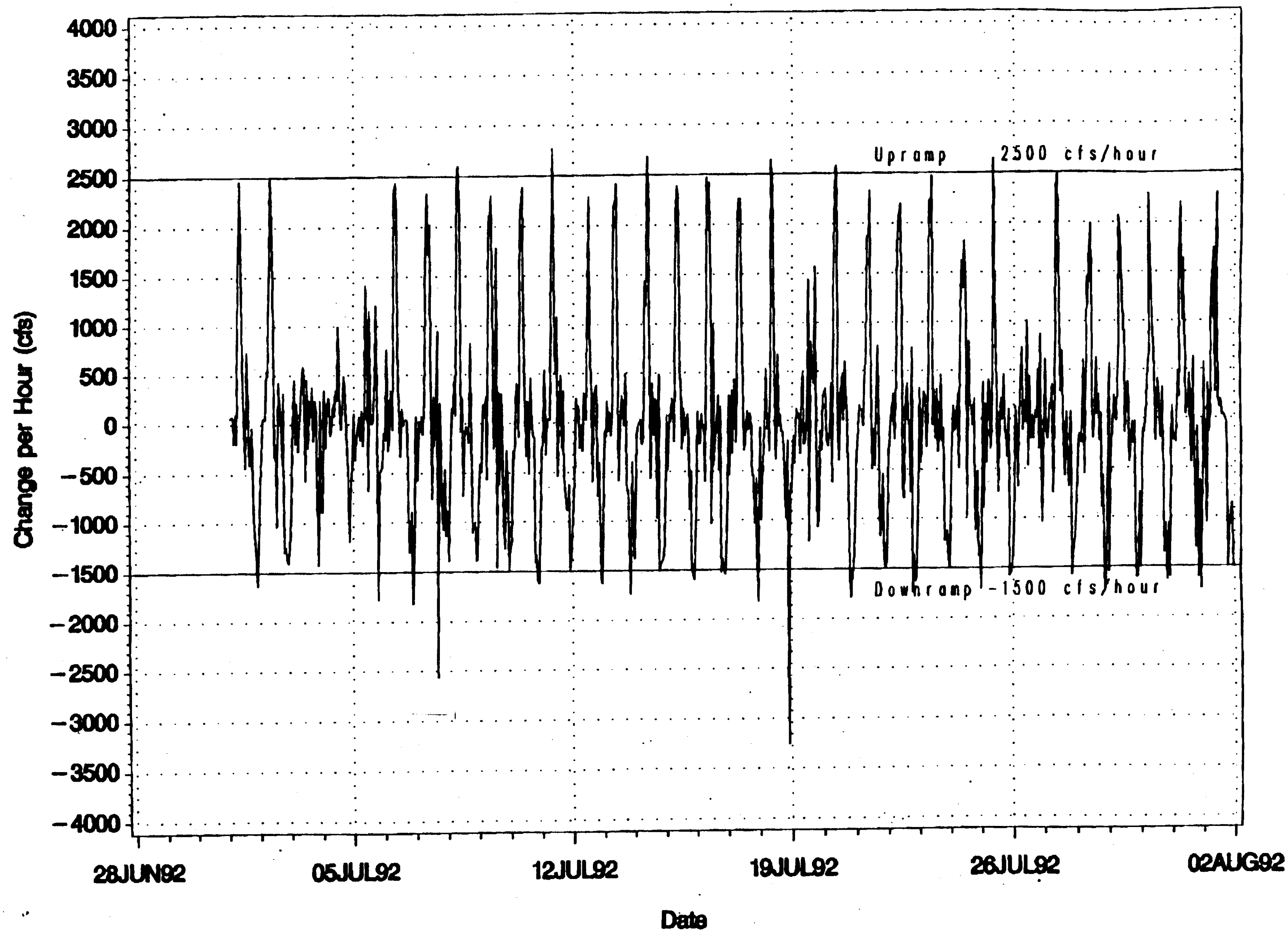
Glen Canyon Dam Releases

Integrated Hourly Values – July 92



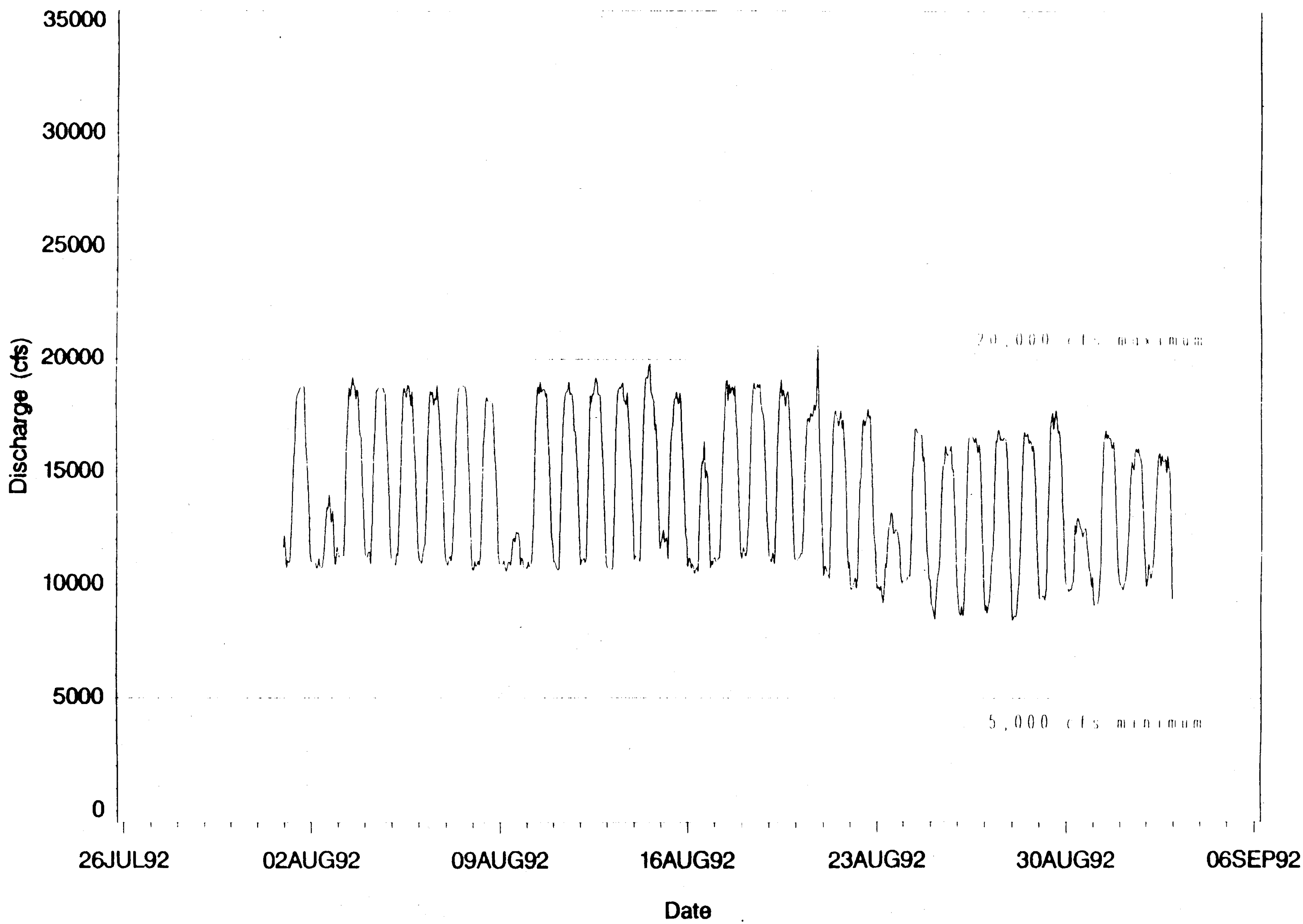
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – July 1992



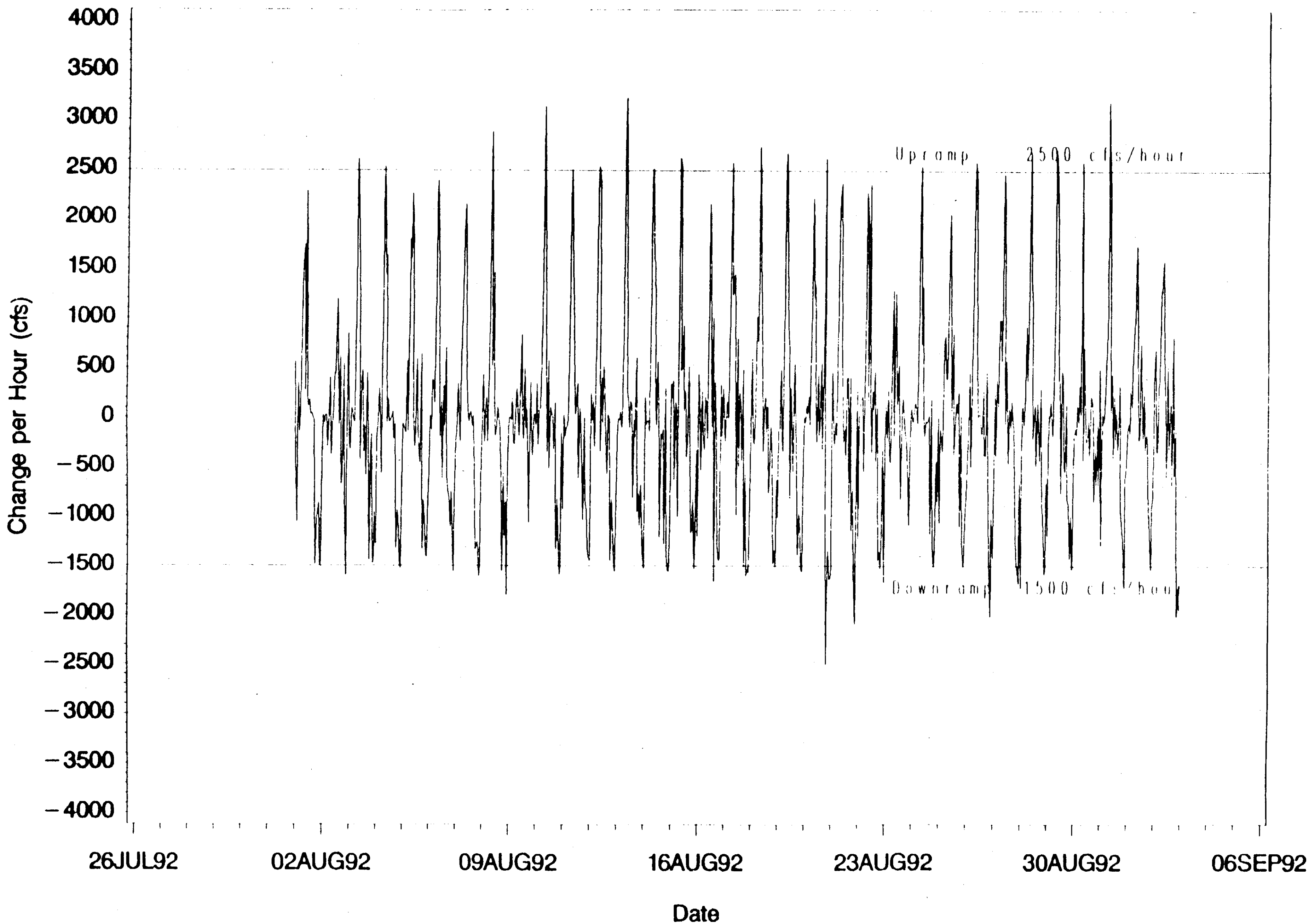
Glen Canyon Dam Releases

Integrated Hourly Values — August 92



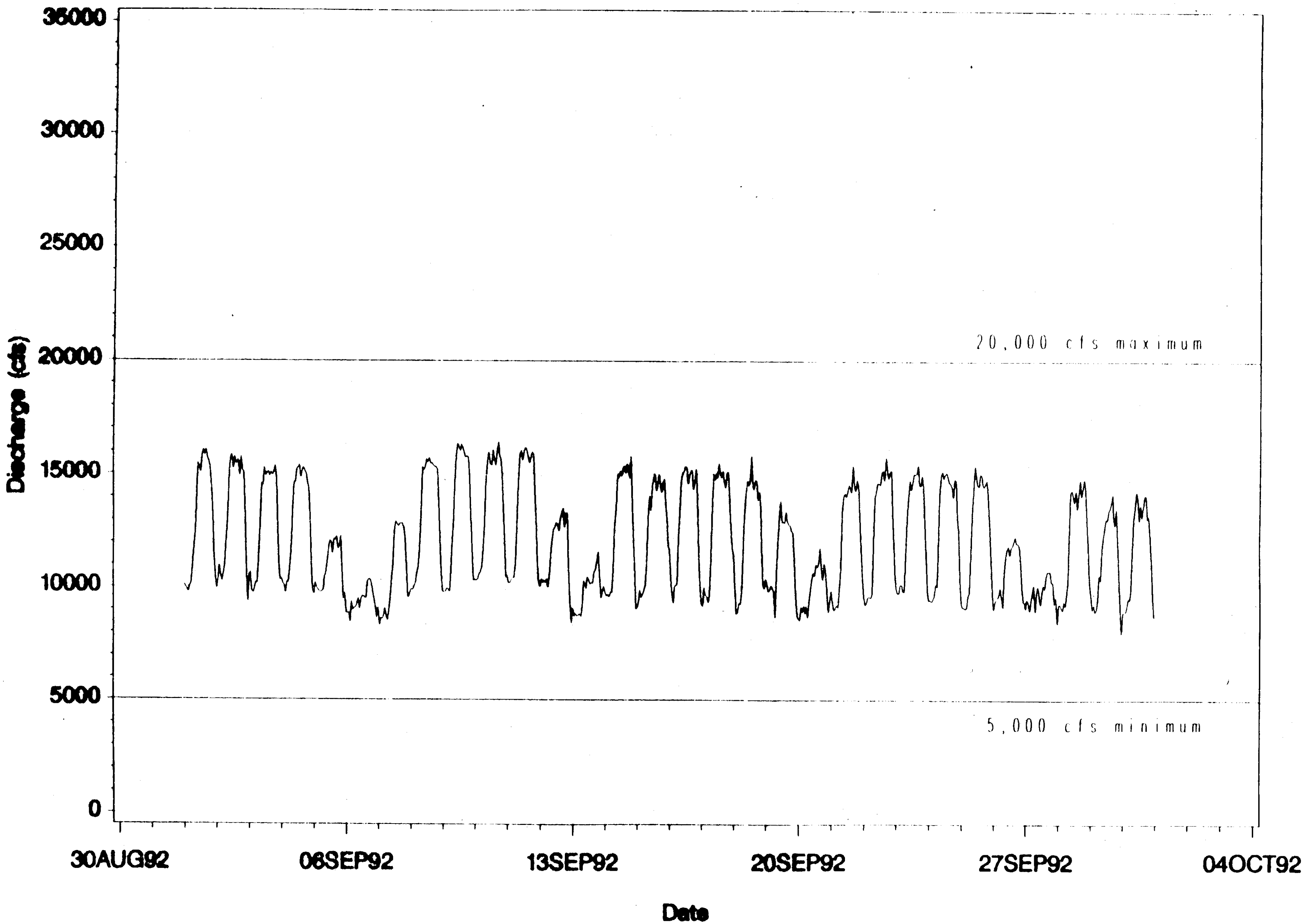
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – August 1992



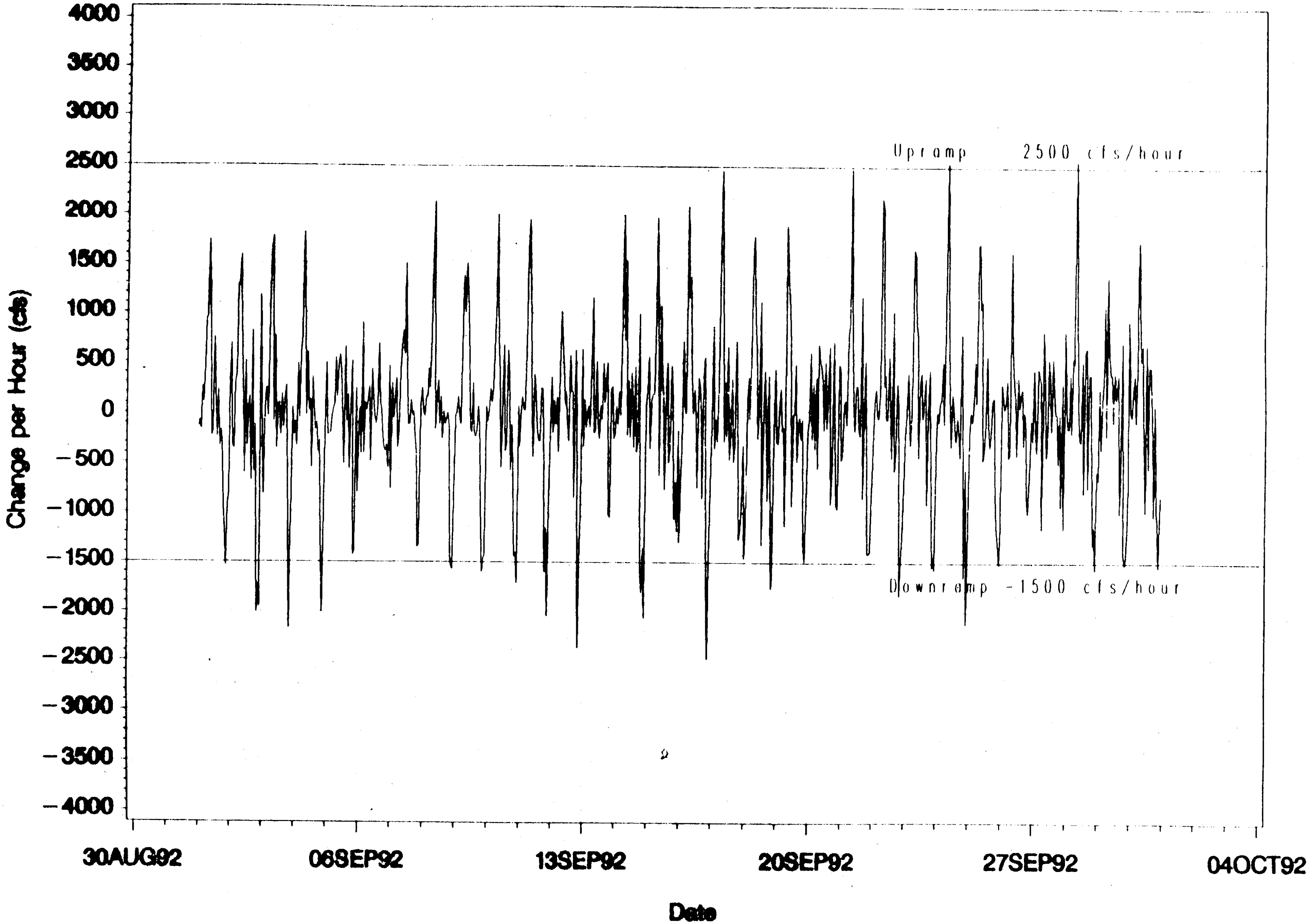
Glen Canyon Dam Releases

Integrated Hourly Values – September 92



Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – September 1992

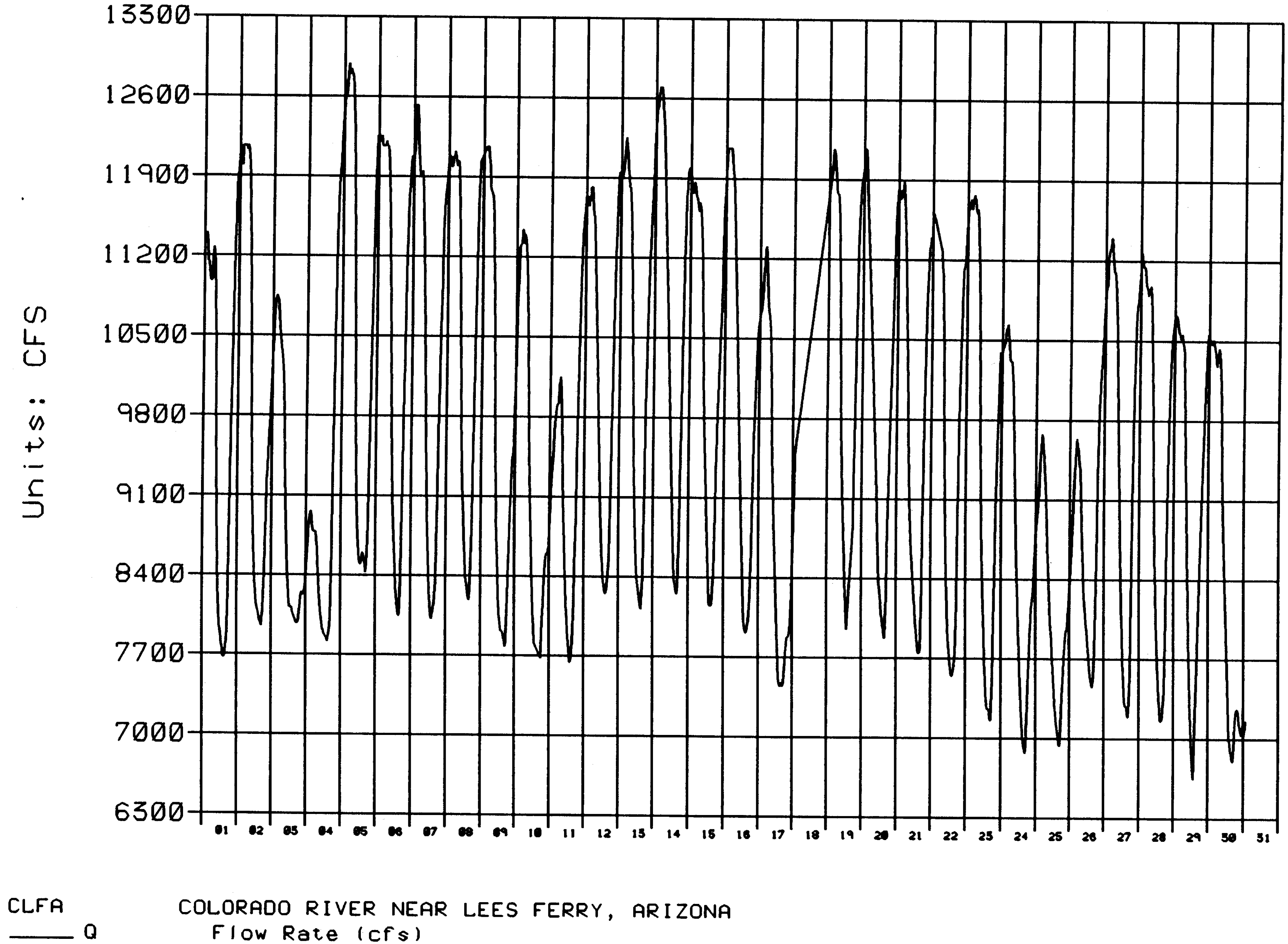


Attachment B

Gaging Stations

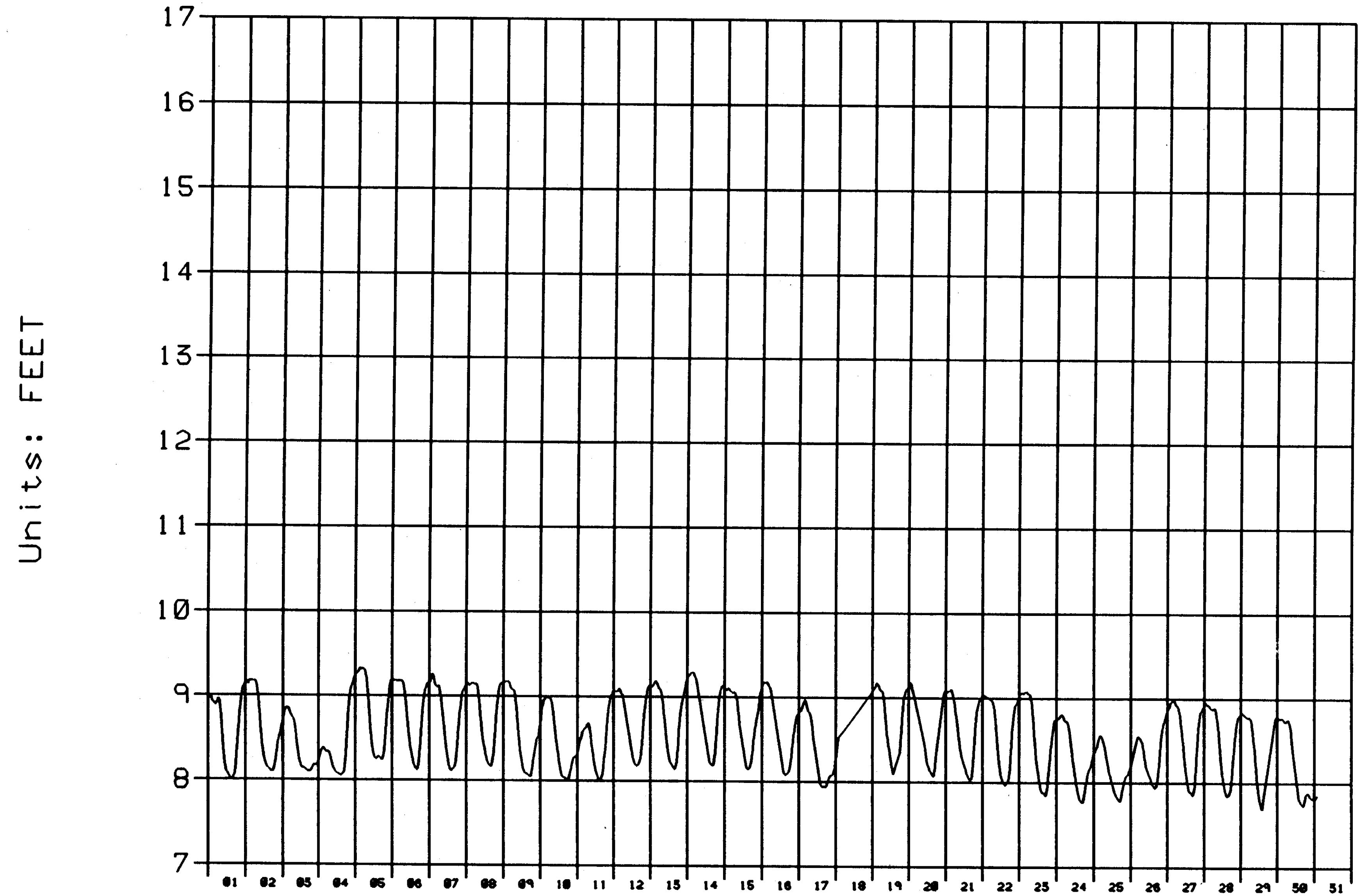
Gaging Stations

Data From 01-MAY-1992 Through 31-MAY-1992
Plotted 14-JUL-92 07:49:20



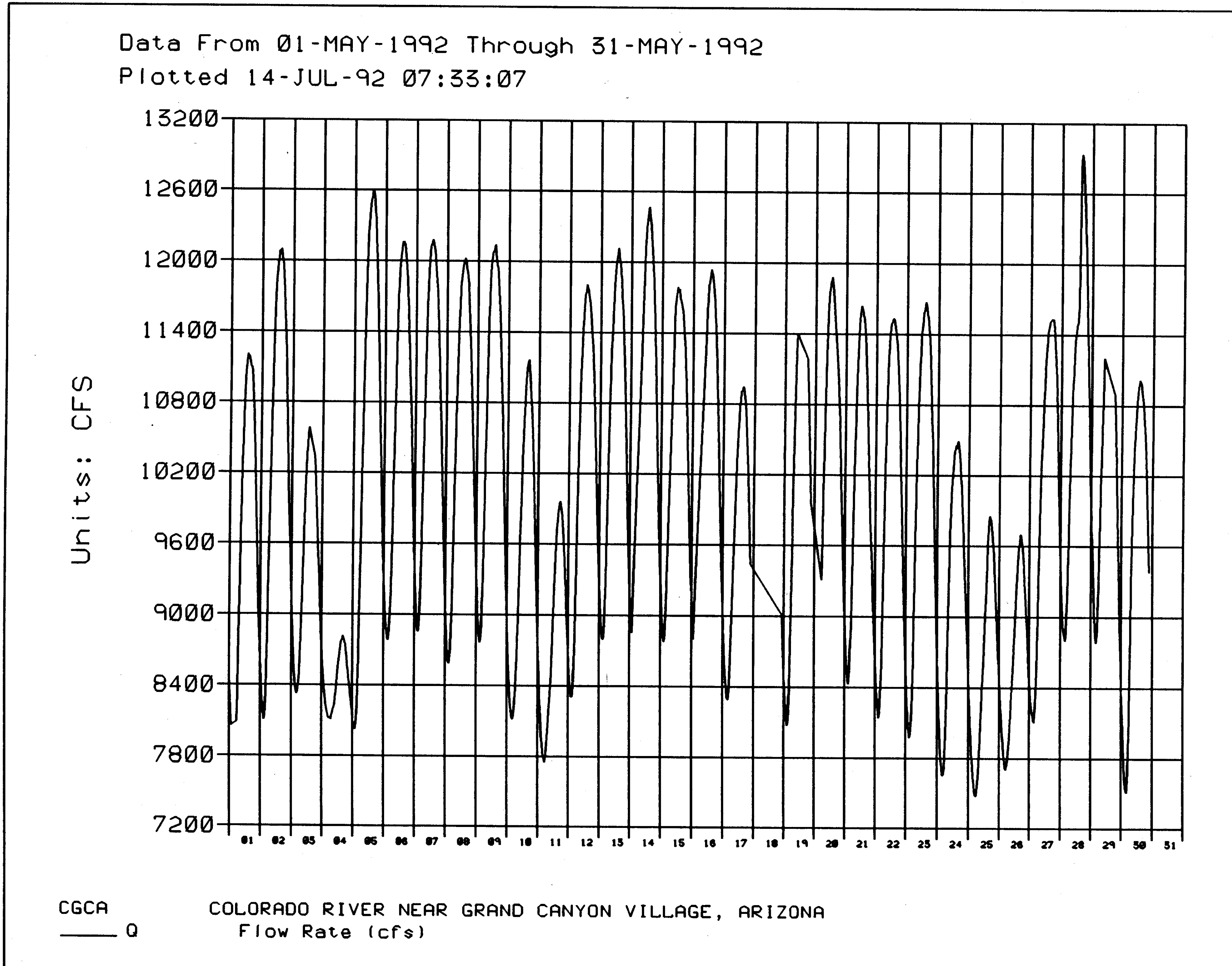
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From Ø1-MAY-1992 Through 31-MAY-1992
Plotted 14-JUL-92 Ø7:45:Ø2



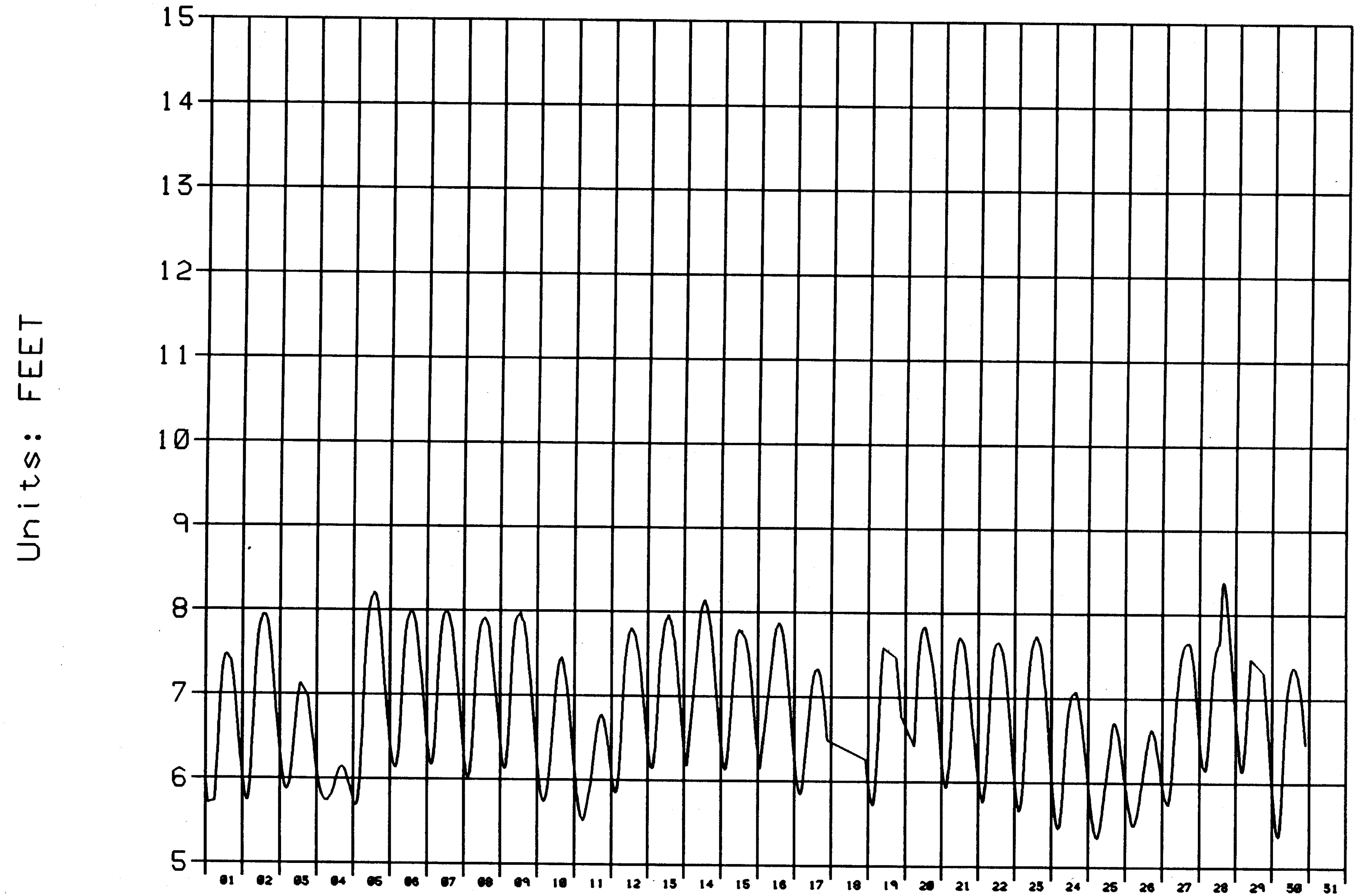
CLFA
——— GH

COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)



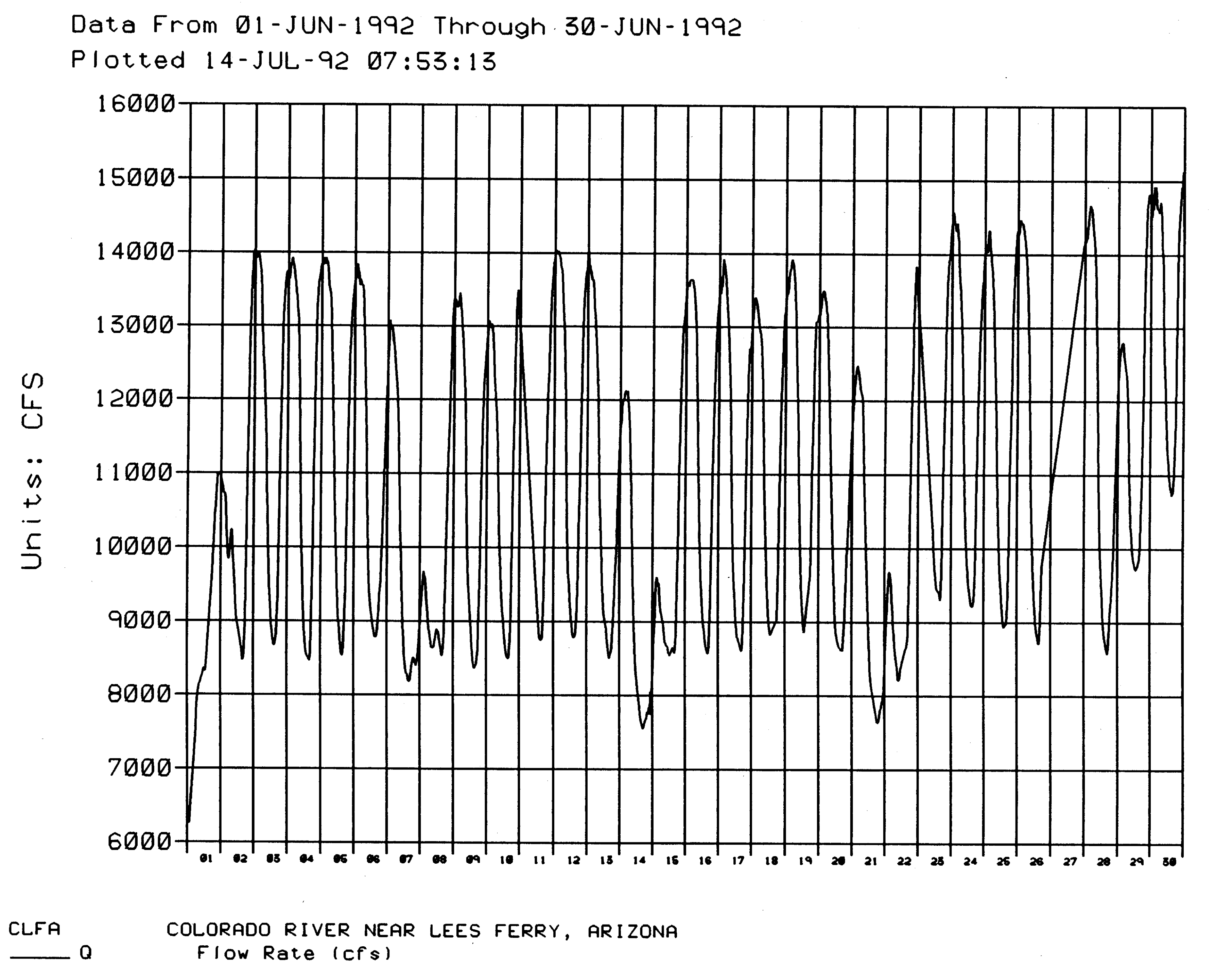
Data From 01-MAY-1992 Through 31-MAY-1992
Plotted 14-JUL-92 07:33:07
Units: CFS
13200
12600
12000
11400
10800
10200
9600
9000
8400
7800
7200
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-MAY-1992 Through 31-MAY-1992
Plotted 14-JUL-92 06:31:02

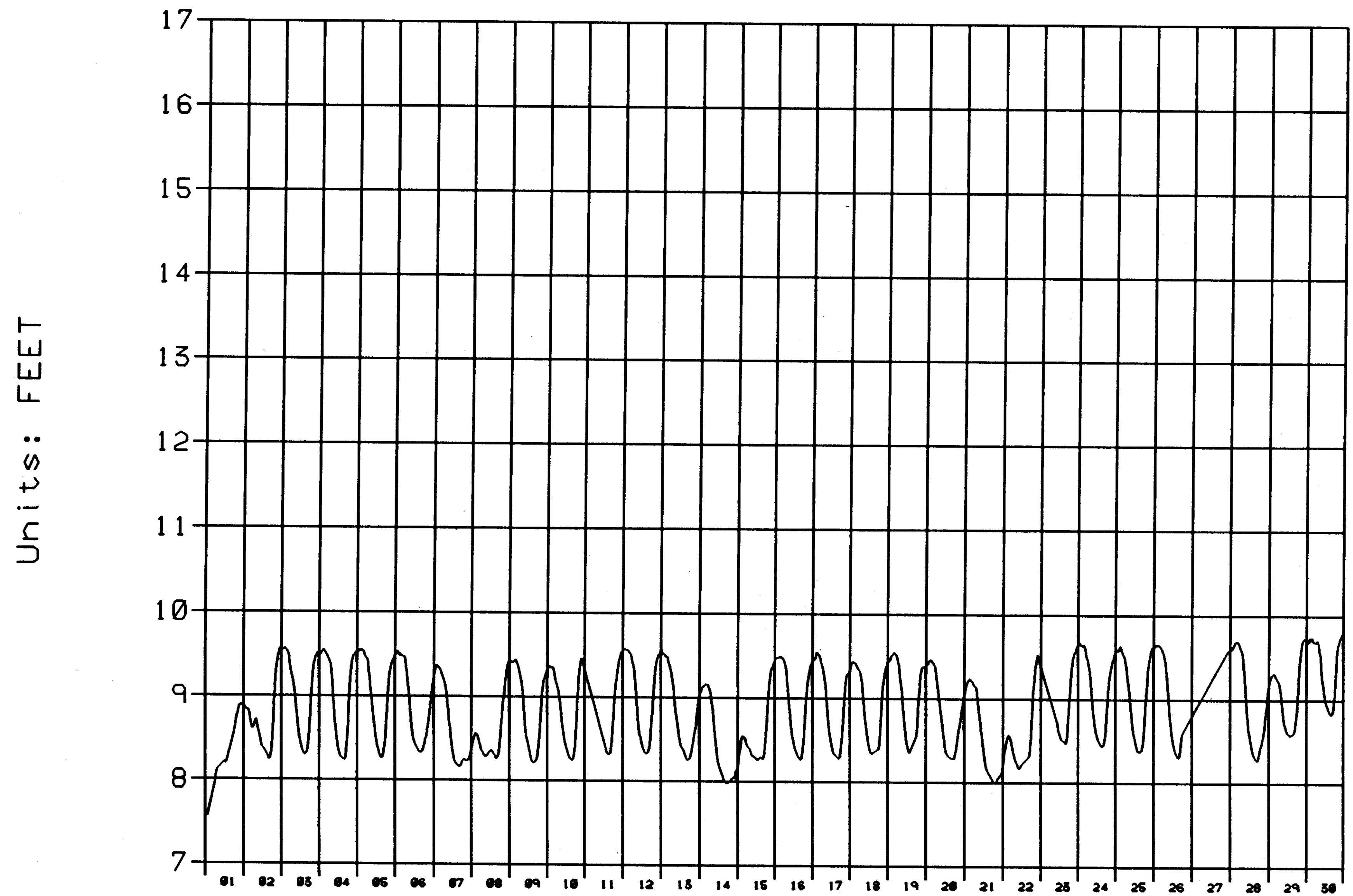


CGCA
GH

COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)


Data From 01-JUN-1992 Through 30-JUN-1992
Plotted 14-JUL-92 07:53:13
Units: CFS
16000
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

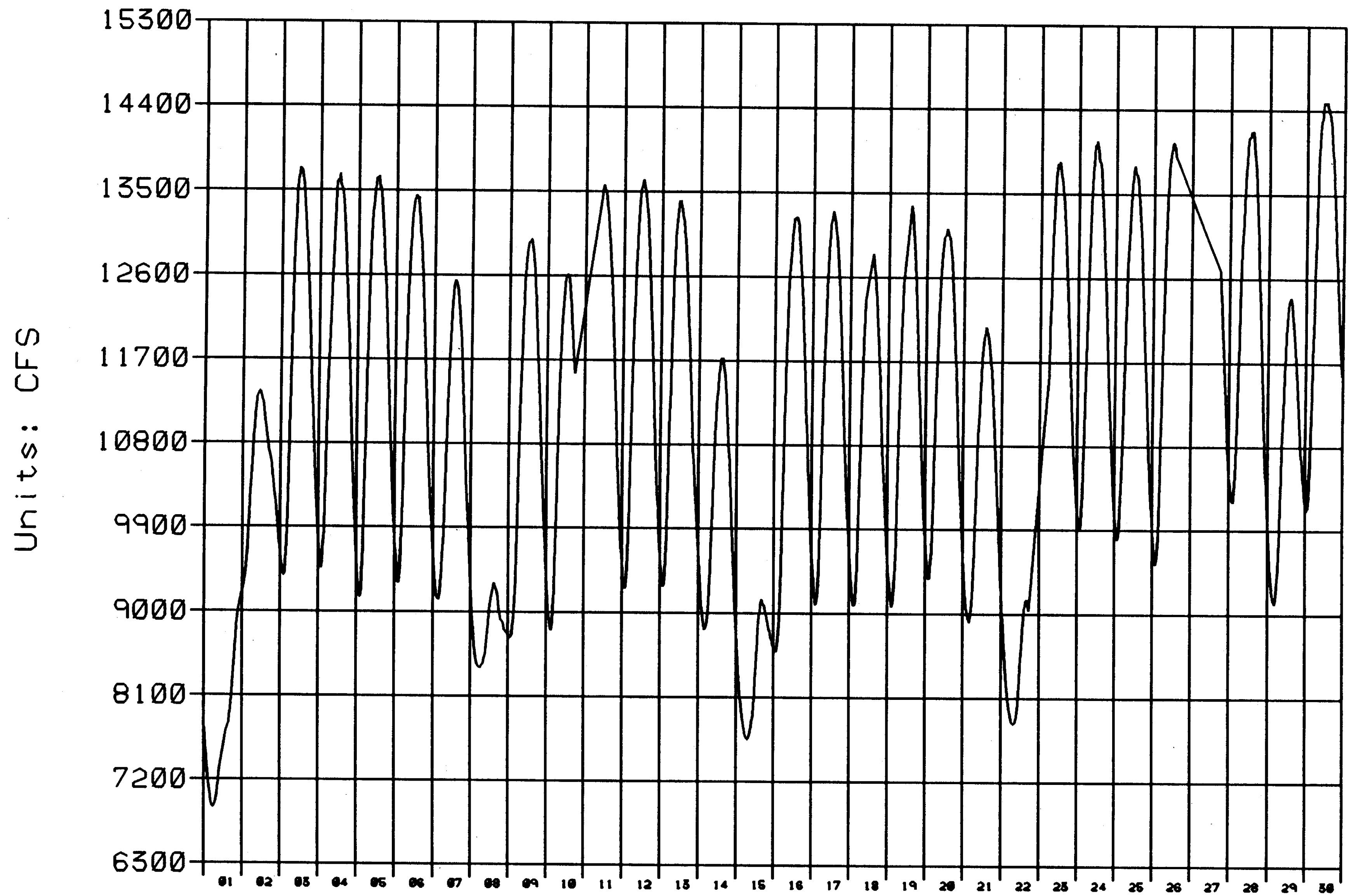
Data From 01-JUN-1992 Through 30-JUN-1992
Plotted 14-JUL-92 07:51:17



CLFA
—— GH

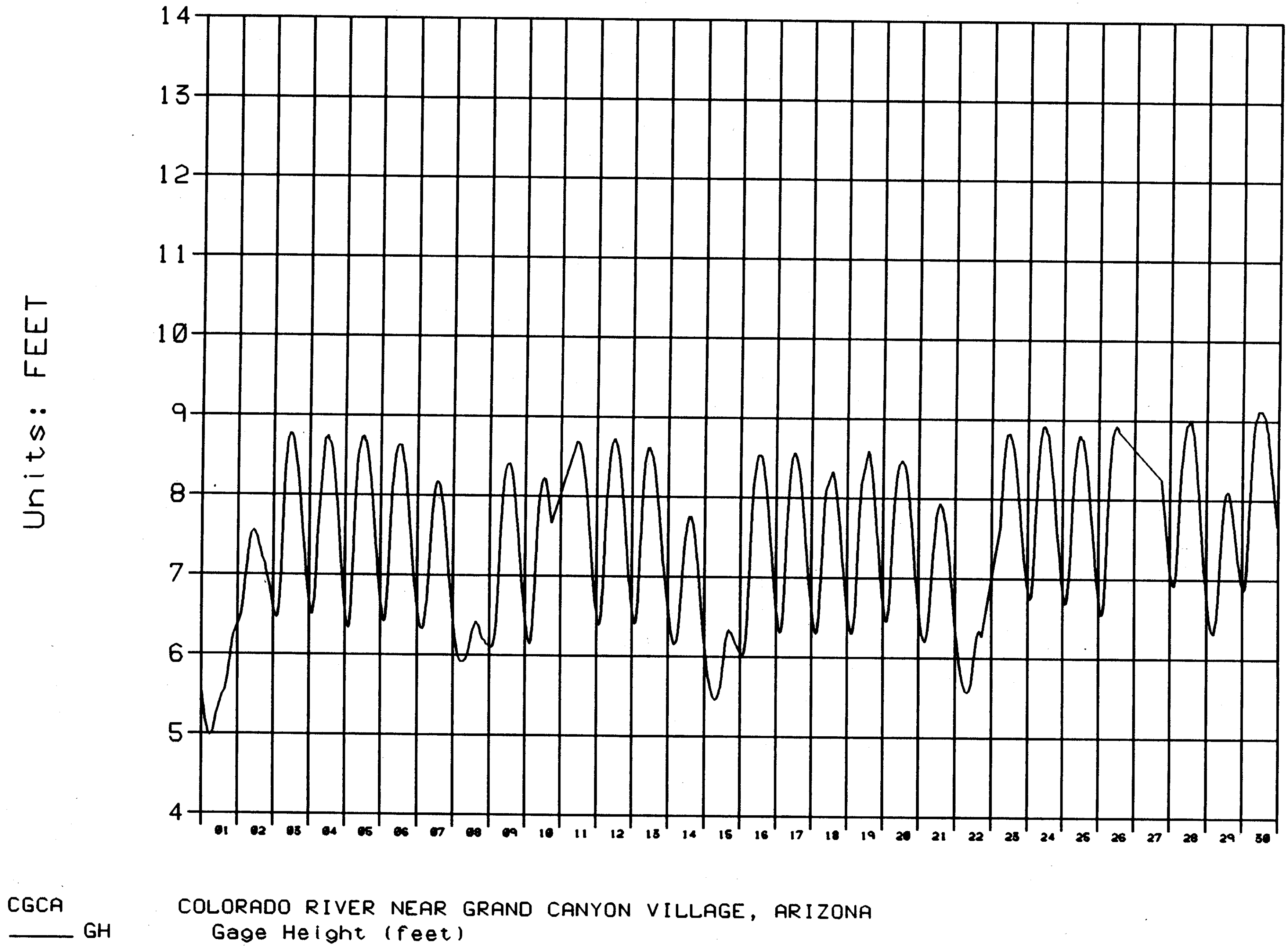
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)

Data From 01-JUN-1992 Through 30-JUN-1992
Plotted 14-JUL-92 07:37:37



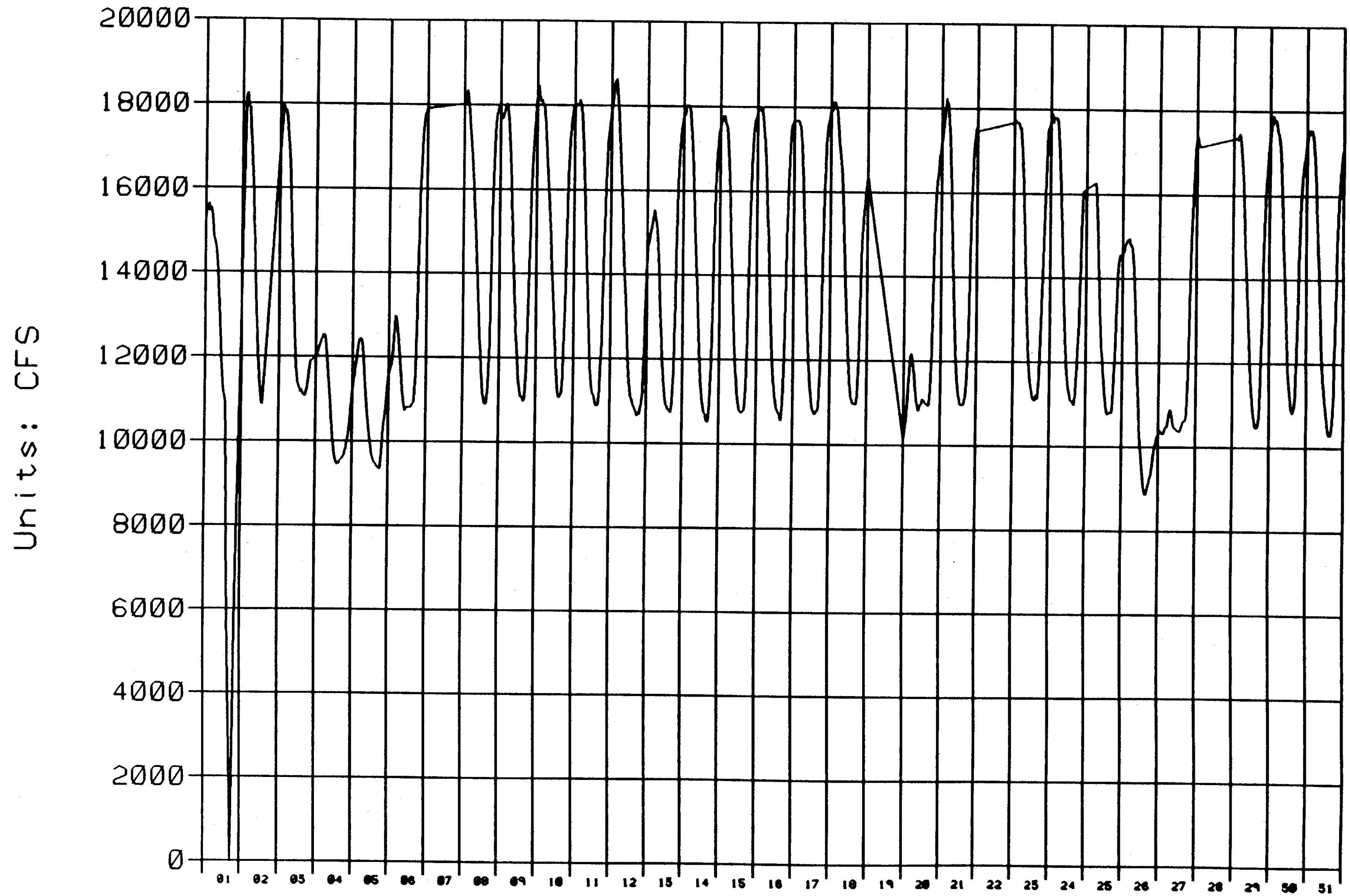
CGCA COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
——— Q Flow Rate (cfs)

Data From 01-JUN-1992 Through 30-JUN-1992
Plotted 14-JUL-92 07:35:22



COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)

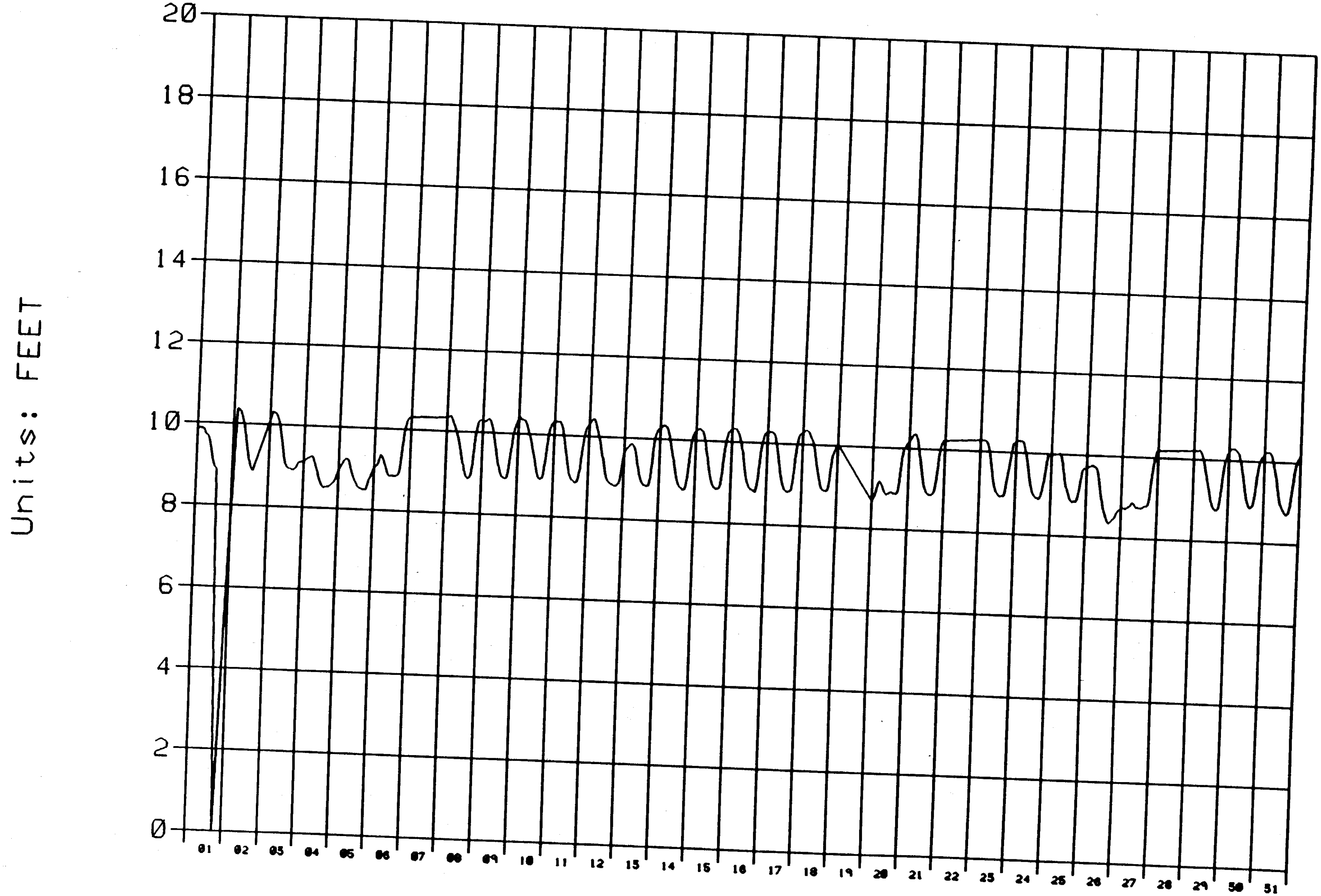
Data From 01-JUL-1992 Through 31-JUL-1992
Plotted 28-OCT-92 13:30:57



CLFA
—— Q

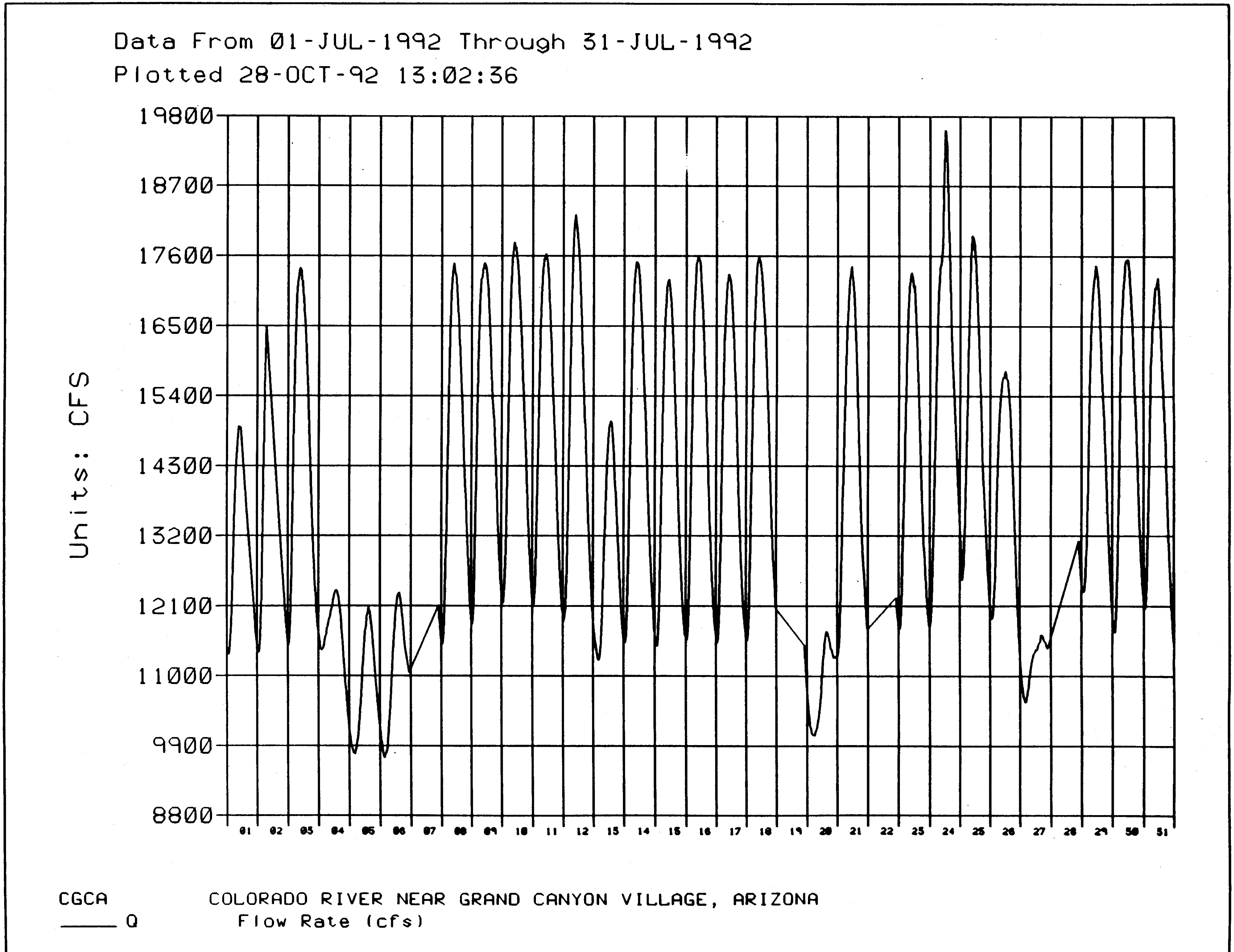
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From Ø1-JUL-1992 Through 31-JUL-1992
Plotted 28-OCT-92 13:20:40

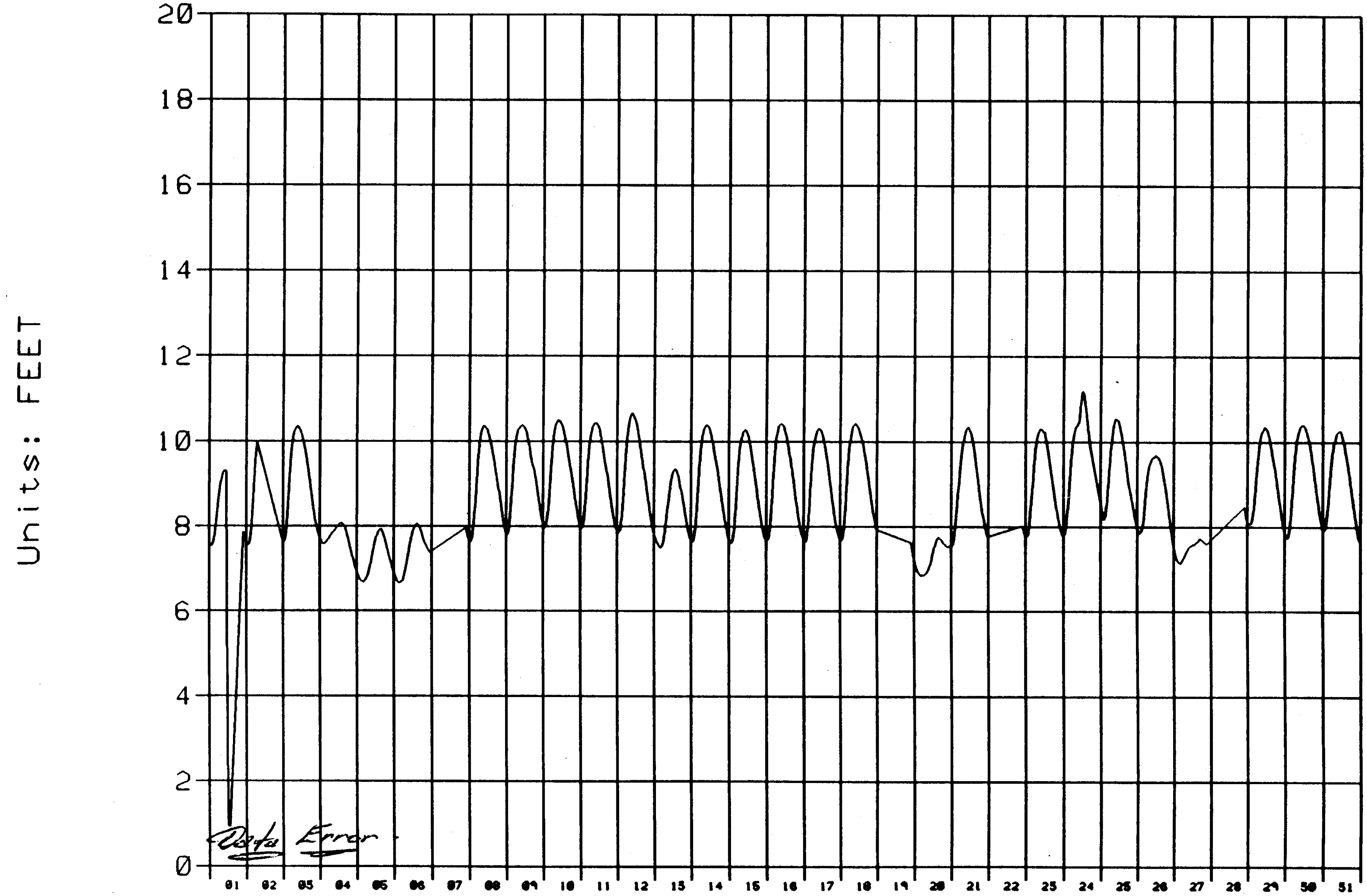


CLFA
——— GH

COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)

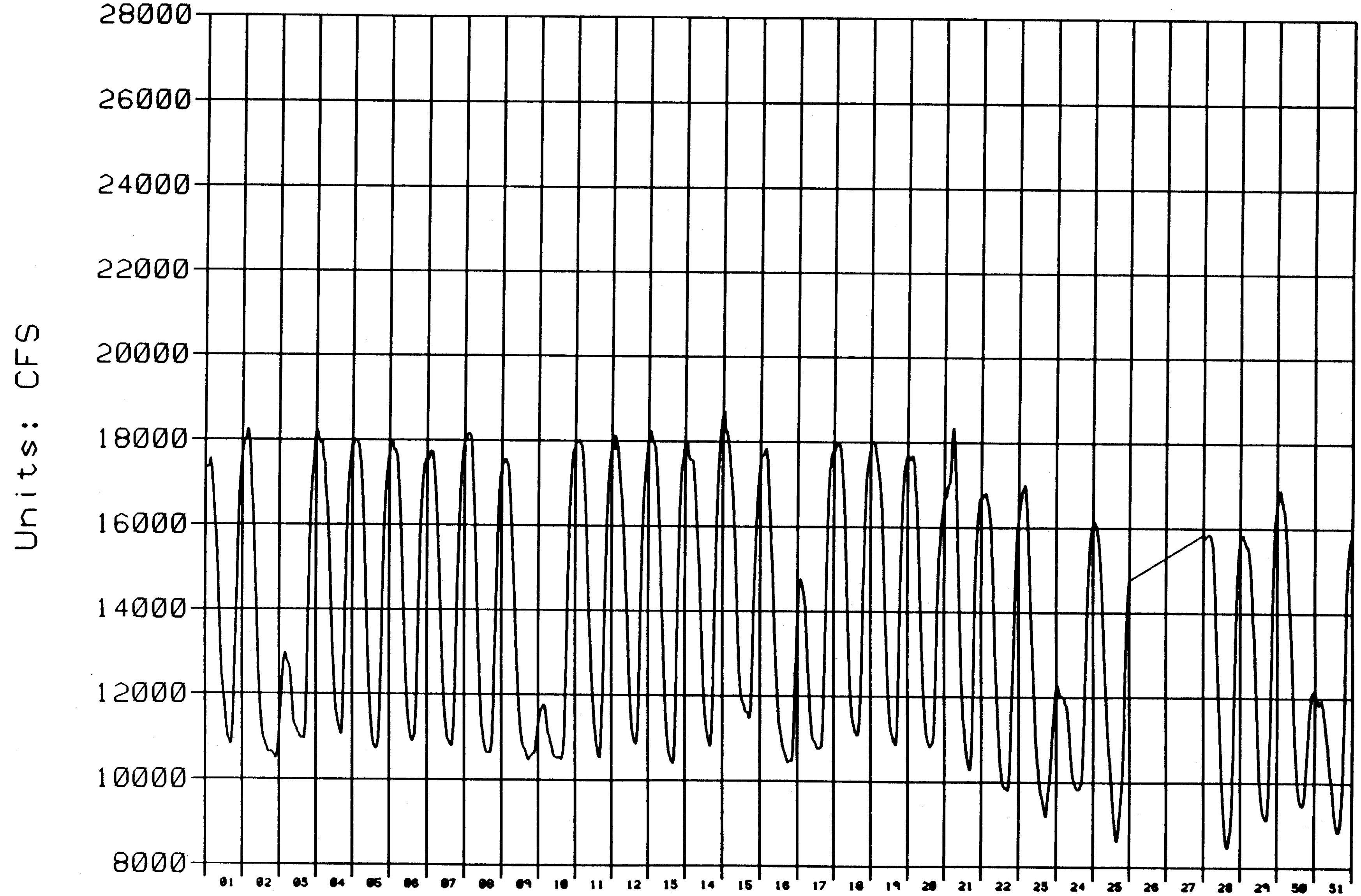

Data From 01-JUL-1992 Through 31-JUL-1992
Plotted 28-OCT-92 13:02:36
Units: CFS
19800
18700
17600
16500
15400
14300
13200
12100
11000
9900
8800
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-JUL-1992 Through 31-JUL-1992
Plotted 28-OCT-92 12:56:23



CGCA COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
—— GH Gage Height (feet)

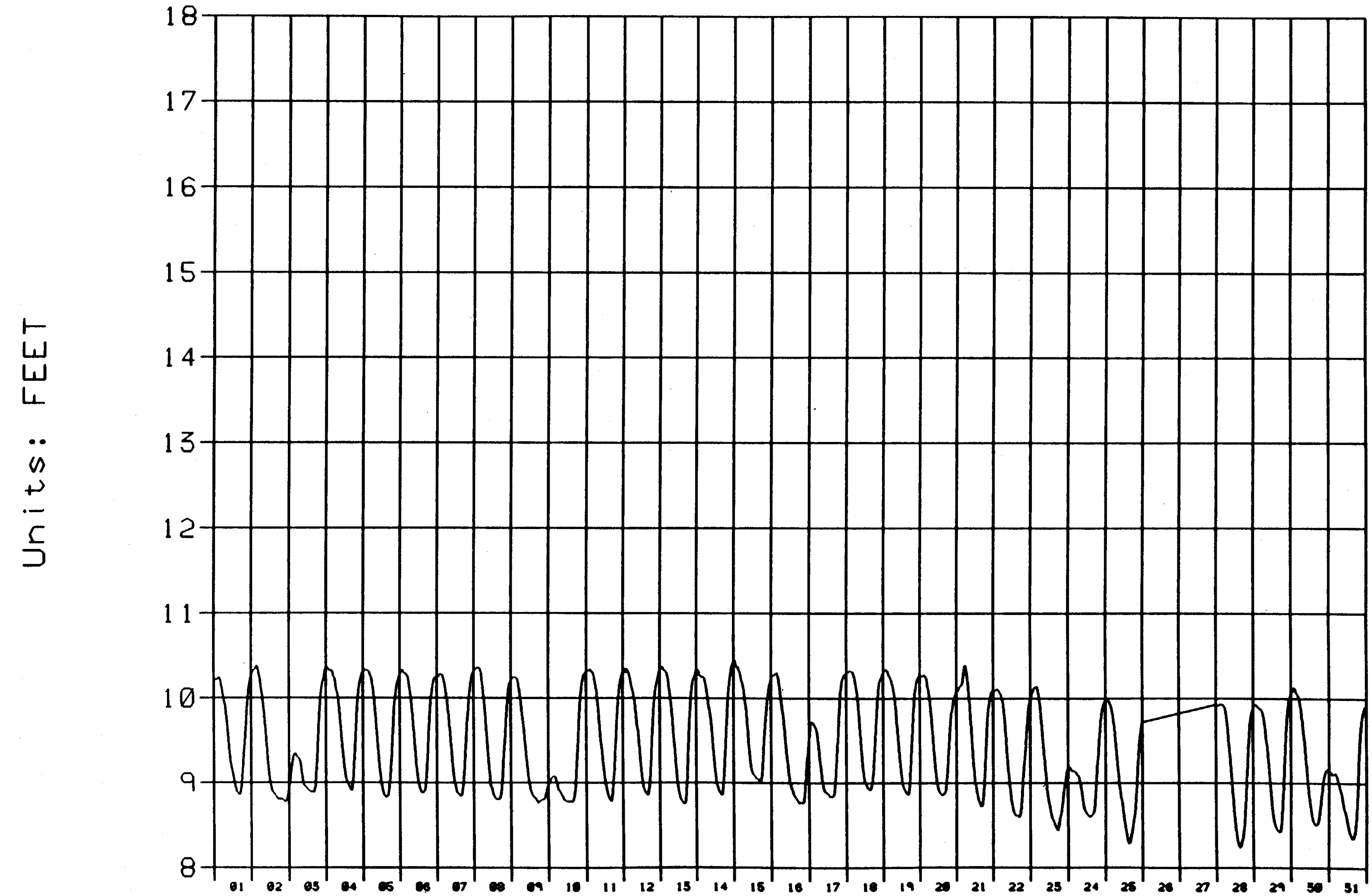
Data From 01-AUG-1992 Through 31-AUG-1992
Plotted 28-OCT-92 13:34:36



CLFA
——— Q

COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

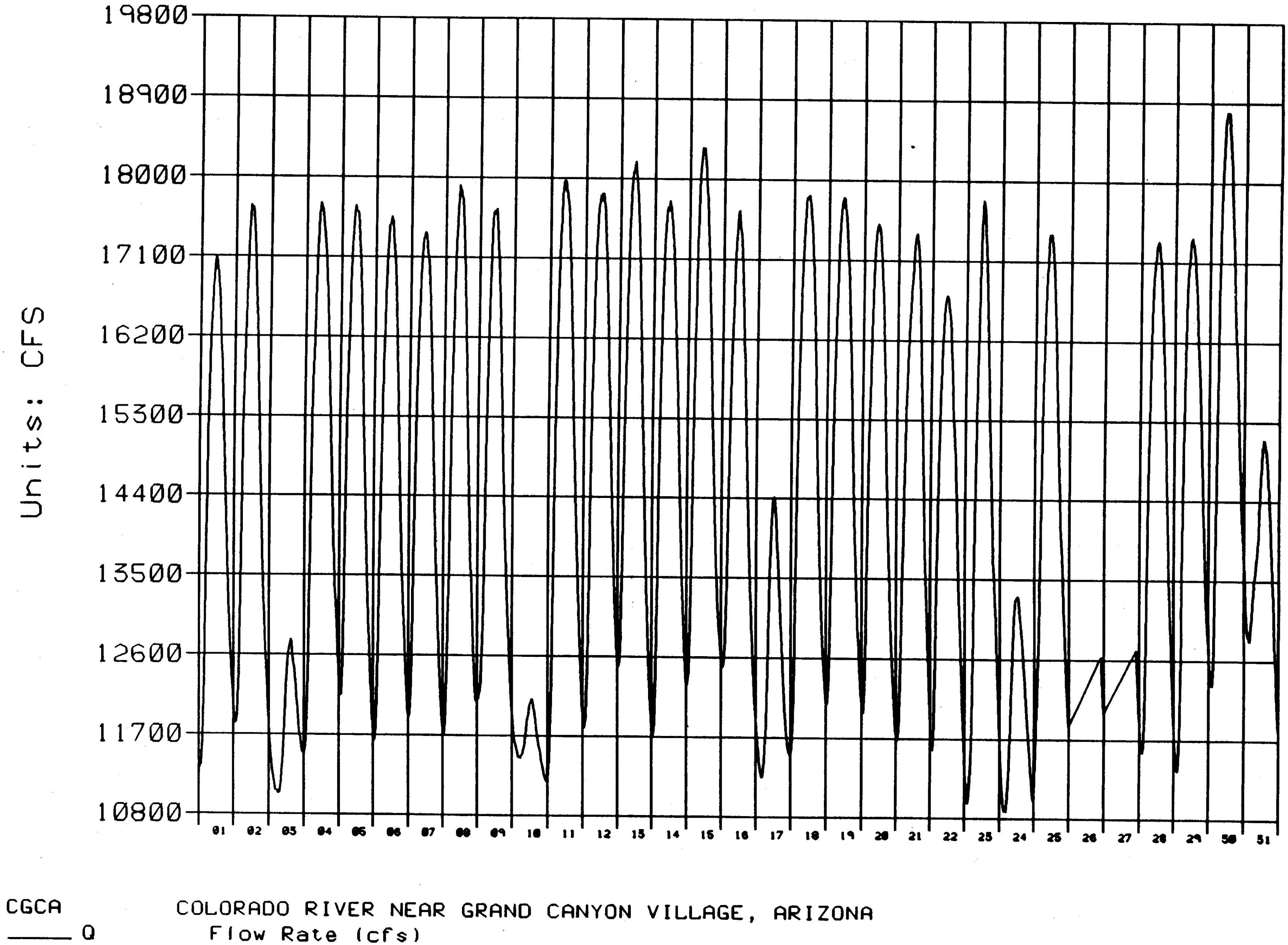
Data From 01-AUG-1992 Through 31-AUG-1992
Plotted 28-OCT-92 13:32:32



CLFA — GH

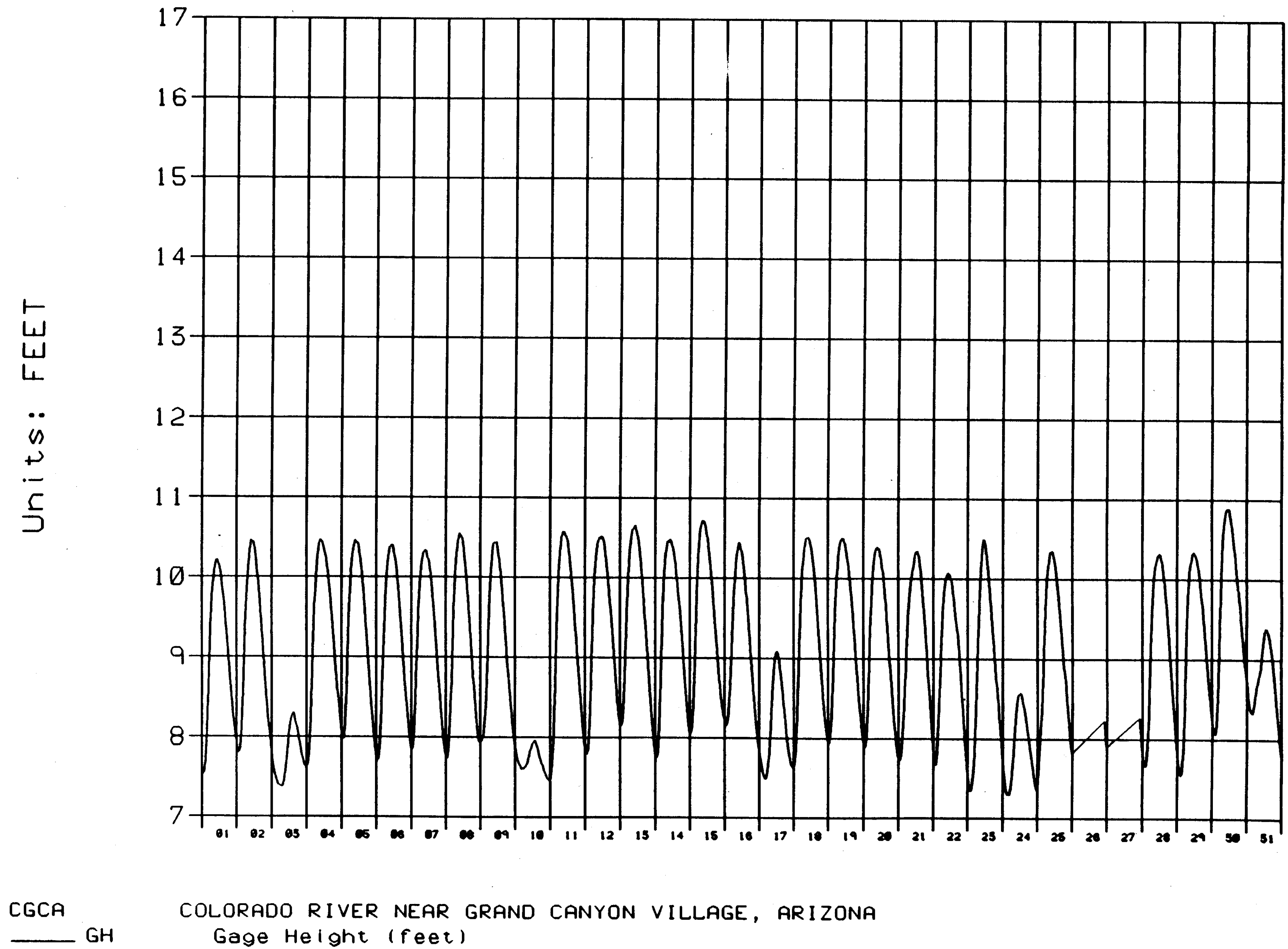
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)

Data From 01-AUG-1992 Through 31-AUG-1992
Plotted 28-OCT-92 13:07:42

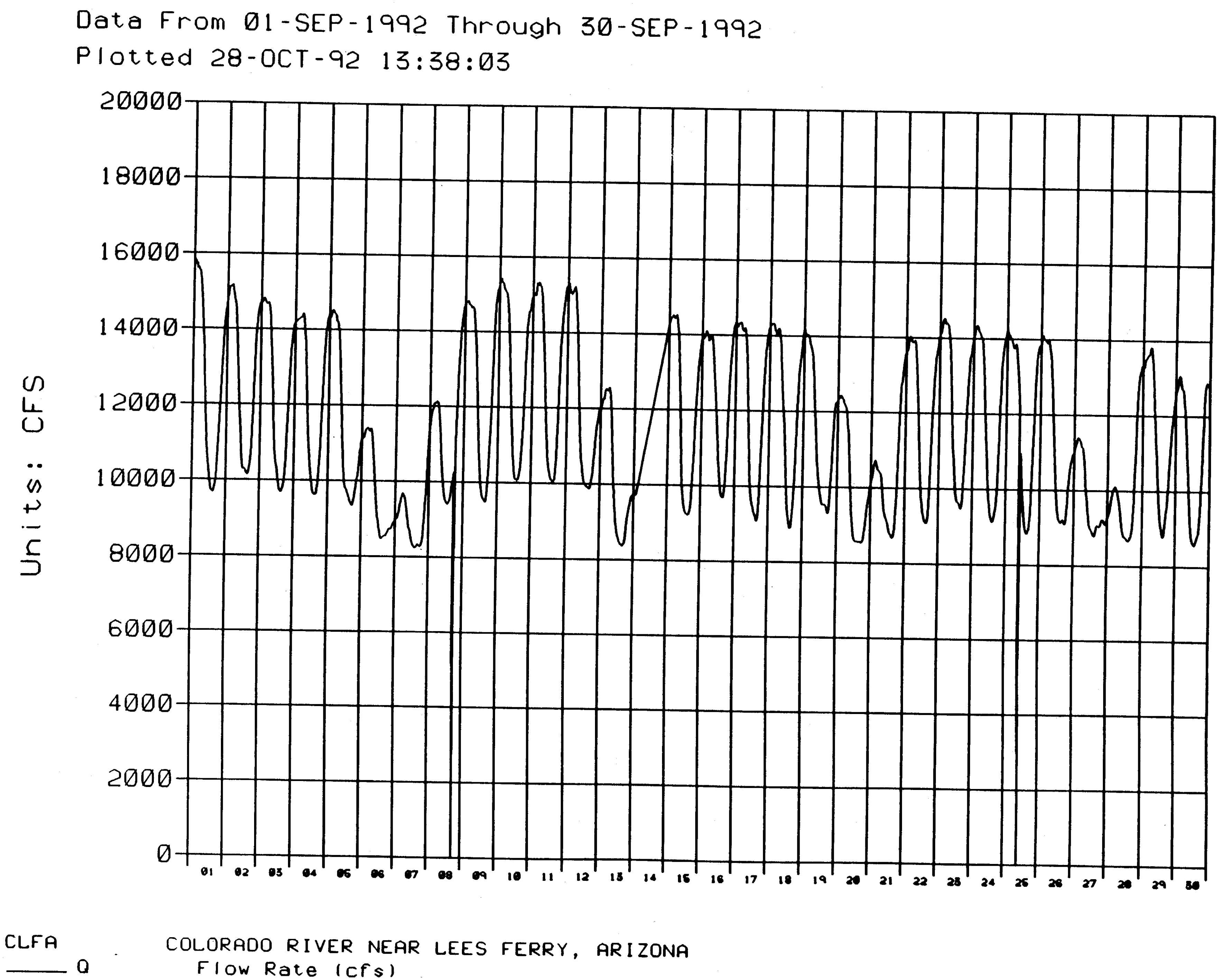


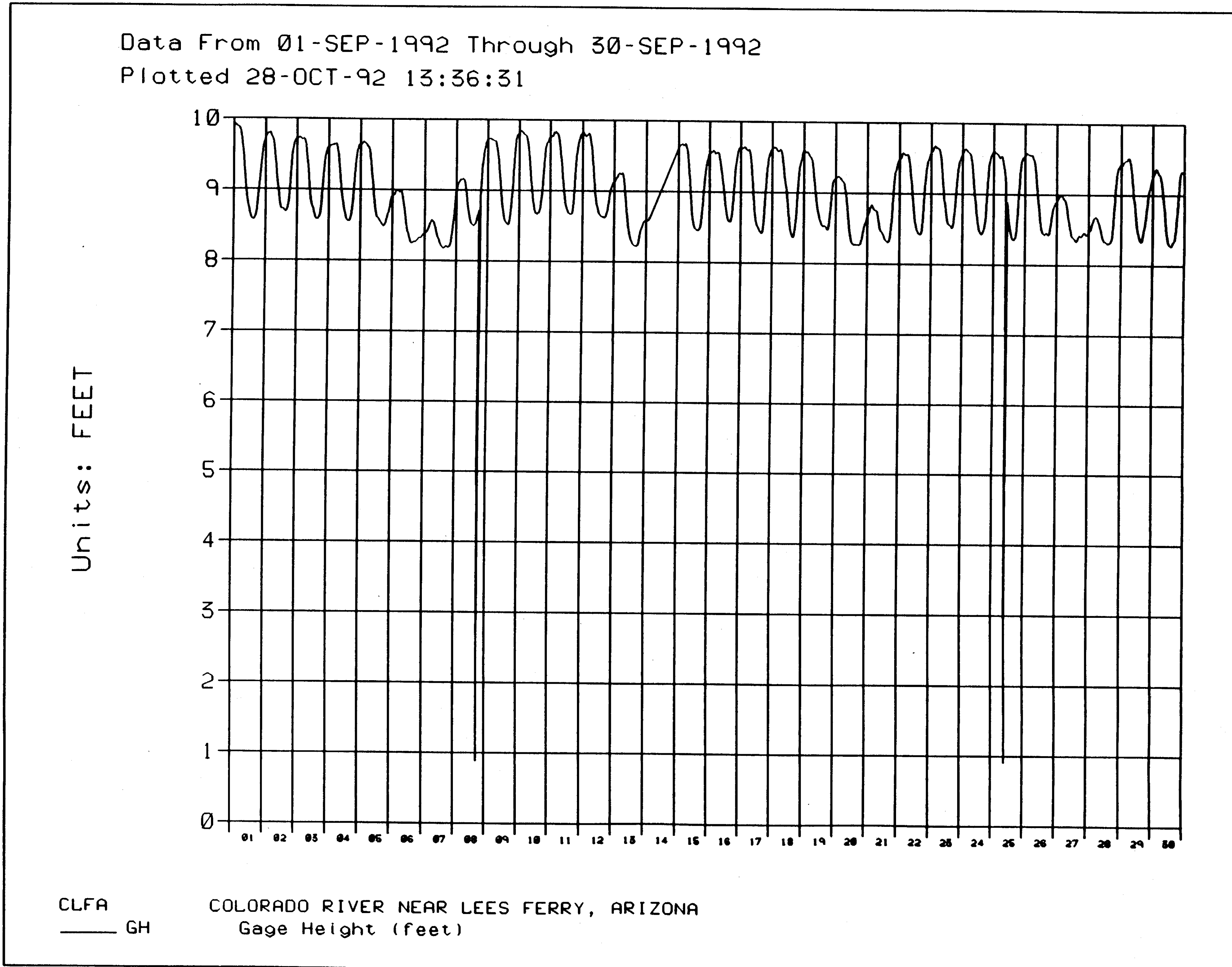
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

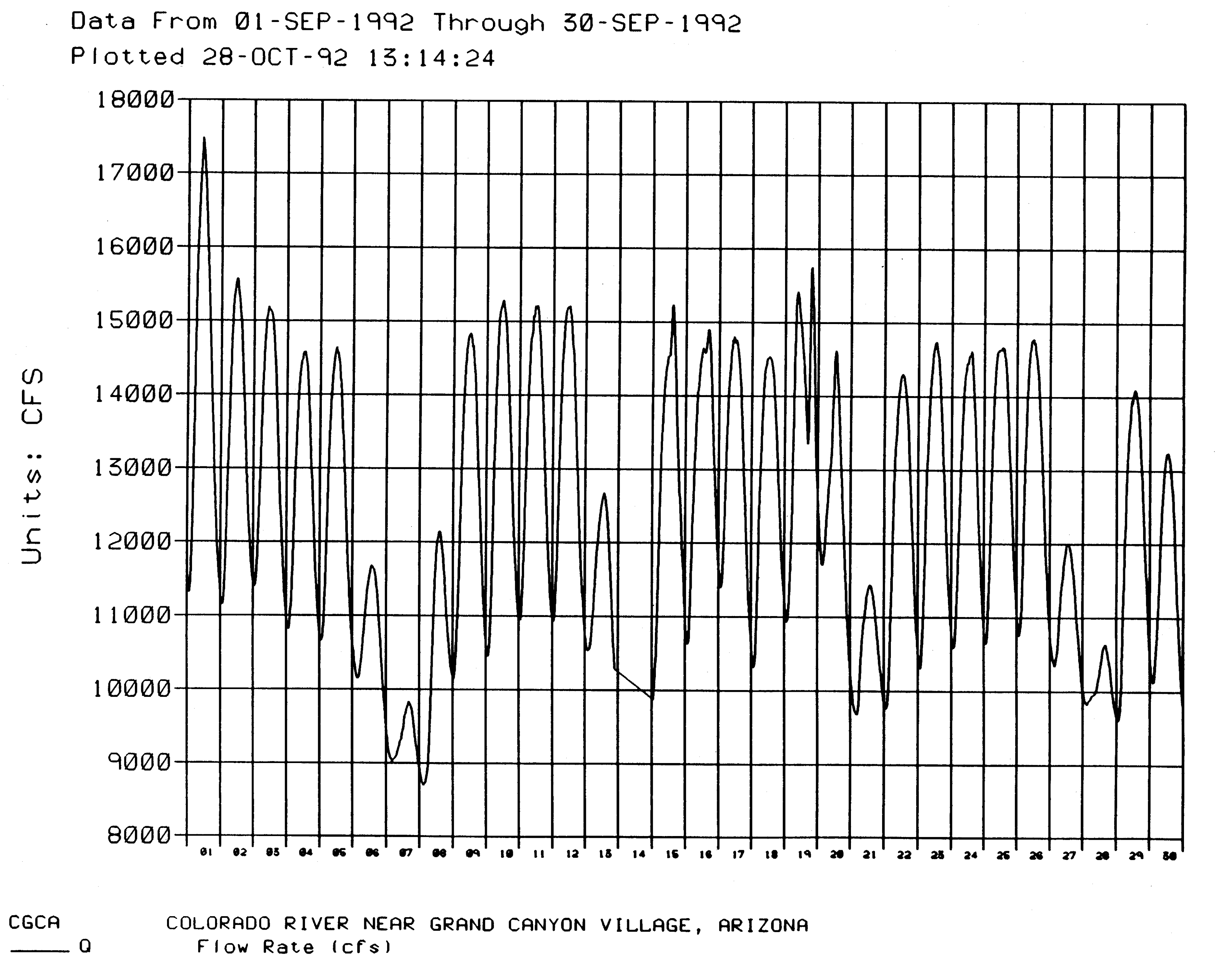
Data From 01-AUG-1992 Through 31-AUG-1992
Plotted 28-OCT-92 13:05:15



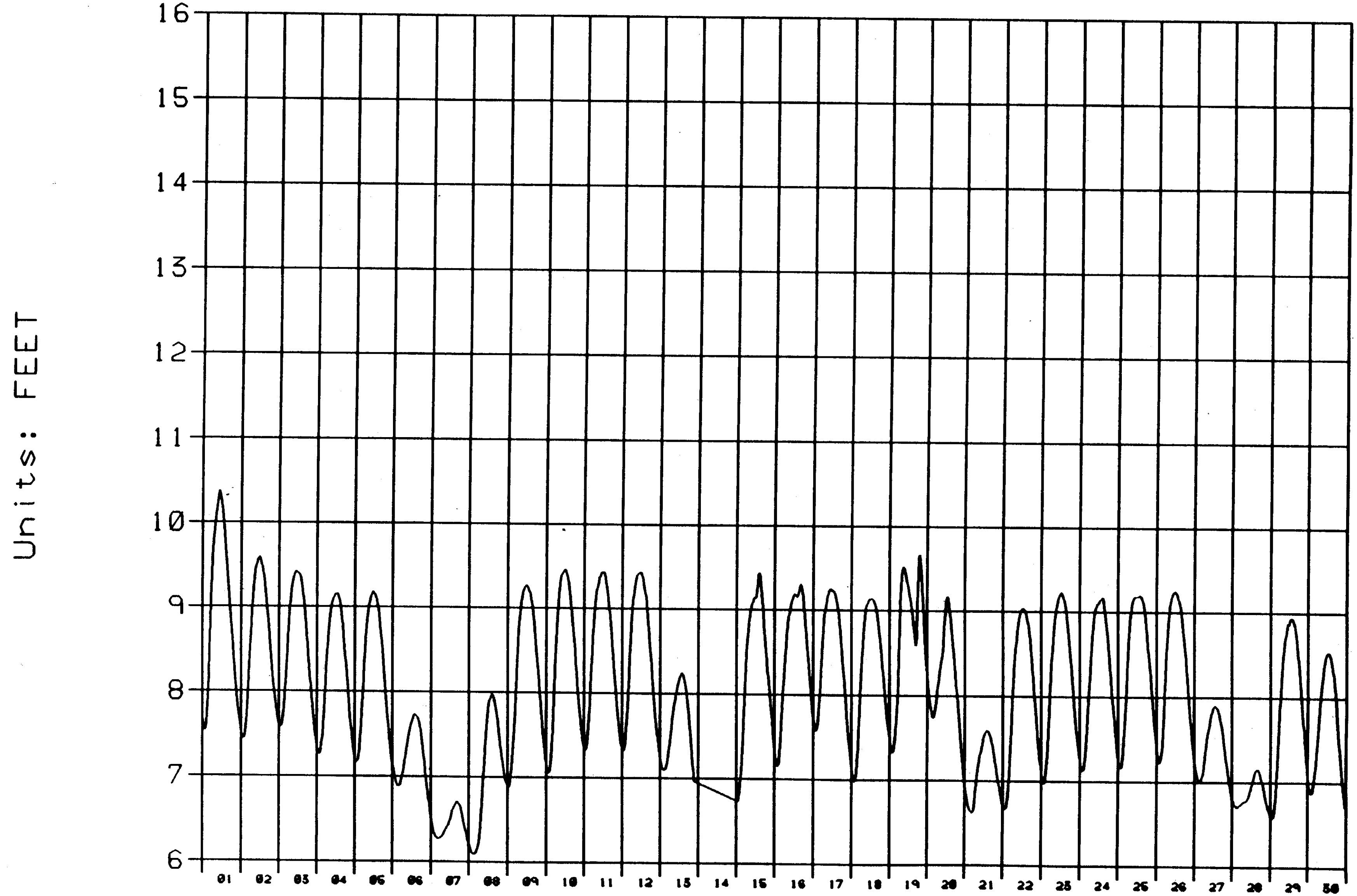
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)


Data From 01-SEP-1992 Through 30-SEP-1992
Plotted 28-OCT-92 13:38:03
Units: CFS
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)


Data From 01-SEP-1992 Through 30-SEP-1992
Plotted 28-OCT-92 13:36:31
Units: FEET
10
9
8
7
6
5
4
3
2
1
0
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
CLFA
GH
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)


Data From 01-SEP-1992 Through 30-SEP-1992
Plotted 28-OCT-92 13:14:24
Units: CFS
18000
17000
16000
15000
14000
13000
12000
11000
10000
9000
8000
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-SEP-1992 Through 30-SEP-1992
Plotted 28-OCT-92 13:10:03



CGCA
—— GH

COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)

Attachment C

Glen Canyon Dam Interim Operations
Western Area Power Administration

GLEN CANYON DAM INTERIM OPERATIONS

Western Area Power Administration

May 1992

WESTERN
AREA POWER ADMINISTRATION

TABLE OF CONTENTS

GLEN CANYON DAM INTERIM OPERATIONS

I. EXECUTIVE SUMMARY

- General Scheduling Under Interim Releases
- Power Scheduling and Real-Time Operations
  - Spring release cost from Aspinall Units totaled $110,800, including lost revenue from Crystal.
- Power Scheduling Concerns
  - Due to low water conditions in the Northwest energy surpluses from BPA did not materialize.
- Analysis of Ramping Events
  - There were 38 deviations: "Control Area Regulation or Disturbance" and "Imports/Exports Different than Preschedule" accounted for 58% of the anomalies.
- Expenses
  - Net expense of interim releases for May is $34,984. Actual and base case prices remained the same in May due to a soft energy market.

II. INTRODUCTION

On August 1, 1992, Interior Secretary Manual Lujan implemented interim flows at Glen Canyon Dam. These interim flows were a considerable departure from previous operation of the dam and have had a significant impact on the daily operation of Western Area Power Administration's (Western) Upper Colorado Control Area.

The impacts of this sudden change in dam operations required Western to implement new scheduling procedures for its customers, develop interim release guidelines for real-time operations, purchase higher priced energy during on-peak periods, and increase the firm-power rates to its customers to cover the additional costs.

Because these operational modifications have occurred within a brief time period, Western and its customers and the utilities interconnected within the Western network have been jolted from predictability in its power operations. The familiarity of daily operations established during the past 20 years has been replaced with uncertainty; however, maintaining a stable and reliable power system operating within the constraints of the Upper Colorado River Basin Fund remains unchanged.

Since their inception, Western and the Bureau of Reclamation (Reclamation) have been successful in meeting the operational parameters of interim flows. Several refinements such as the 24-hour rolling period, the 30-day rolling period, and regulation caused minor problems. Once these issues were resolved by the Cooperating Agencies, Western and Reclamation responded in kind.

The following sections are a review of Power Operations for the reporting period.

III. SCHEDULING

A. General Scheduling Procedures Under Interim Release Operations

Scheduling procedures associated with the delivery of Salt Lake City Area Integrated Projects (SLCA/IP) firm capacity and energy have been modified to accommodate the release restrictions imposed on Glen Canyon Powerplant with interim release constraints.

Under previous scheduling procedures, SLCA/IP contractors were allowed to preschedule their monthly capacity allocation on an hourly basis, within established minimum and/or maximum schedule limits set by contract. Energy is delivered under the capacity up to the contractors' monthly energy entitlement as defined in Exhibit A of their electric service contract. Capacity and associated energy schedules could have been changed (real-time) to adjust to changes in system load.

Interim release restrictions have limited Western's ability to accommodate hourly changes in the preschedules due to reduced capacity availability and have required Western to request customer prescheduling 3 days in advance in order to match firm loads to available project resources and substitute purchases for any hourly deficits. Hourly changes to preschedules has been restricted by the lack of system flexibility. The burden to adjust to changes in real time load has shifted from the contractors' use of their SLCA/IP resource to the contractors' alternate resources. A majority of these other resources are thermal and have higher costs in their use.

After Western receives the contractors' advance firm schedules, project generation is patterned hourly to optimize system capacity. During times of surplus generation, the surplus is scheduled when the energy reaches its greatest value. In times of hourly deficiencies, unit capacity is scheduled over system peaks to the maximum available, and hourly shortages are met through nonfirm energy purchases.

During periods of normal operations, there were no hourly deficiencies due to restricted flows from Glen Canyon. System energy shortages were supplied through nonfirm purchases scheduled in equal amounts across all hours, divided into on and off-peak periods. Hourly peaks were covered with available project capacity.

Under interim operations, Western must determine when the system peak loads will occur and purchase nonfirm energy to cover shortages during specific hours, requiring advance scheduling of both project generation and nonfirm purchases. Due to the very narrow ramping restrictions at Glen Canyon, off-peak generation has been increased and energy, normally purchased off-peak when generation was low, is purchased during higher priced on-peak periods.

Interim release conditions have forced scheduling and dispatch personnel to monitor projected water releases and hourly generation levels very carefully.

With interim release conditions, Glen Canyon Powerplant must operate within very specific daily fluctuation limits. Peaking capacity required to serve firm load obligations unavailable at Glen Canyon must be obtained from other project resources. These resources have daily water limitations which must be maintained. Any large deviations from anticipated generation levels which may occur on a real-time basis could affect prescheduling for several days. To avoid this, a very comprehensive set of interim release guidelines have been developed for dispatchers to use when running the power system during real-time operations. One individual is solely devoted to coordinate prescheduling with dispatch. Not surprisingly, this new set of procedures brought on by Interim Flow restrictions complicates "normal" Glen Canyon operations.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for the Month of May 1992

May releases from Glen Canyon were scheduled at 595,000 acre-feet. The weekday generation pattern was prescheduled at 7,700 cfs (278 MW) during off-peak hours ramping up to a maximum of 12,500 cfs (452 MW) during on-peak hours for a majority of the month. This follows the daily maximum fluctuation restriction of 5,000 cfs (174 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

May was a very busy month on the SLCA/IP power system. <u>In addition to Glen Canyon interim releases, special high spring releases were also scheduled by Reclamation from both the Flaming Gorge and Aspinall Units—Crystal, Morrow Point, and Blue Mesa—for fish habitat enhancement on the Green and Gunnison Rivers</u>. Spring peaking flows began from Flaming Gorge on May 4, about 3 weeks earlier than expected. Releases from Flaming Gorge were increased an equivalent of 1,983 acre-feet (1,000 cfs) per day for 3 days until a maximum release through the turbines of 4,200 cfs (130 MW/hr) was attained. This maximum release was held for 7 days and then reduced an equivalent of 793 acre-feet (400 cfs) per day until plant generation hit 24 MW/hr (800 cfs minimum flow). The special spring flow lasted for a total of 19 days and released approximately 110,000 acre-feet of water. Total water released from Flaming Gorge for the month of May totaled 137,000 acre-feet or about 57,000 acre-feet more than May 1991. Runoff into Flaming Gorge in the spring of 1992 was the lowest on record. The combination of high spring releases and low inflow will significantly limit releases from Flaming Gorge this next winter. Flaming Gorge releases are scheduled to be 60,000 acre-feet from November 1992 through March 1993. This will effectively limit Flaming Gorge to minimum releases all winter with no flexibility increasing regulation and system swing pressure on Glen Canyon.

The spring release from the Aspinall Units began on May 11 and lasted 13 days. Releases from Crystal reached 4,000 cfs at maximum output (2,000 cfs through the turbine) with 3,000 cfs flowing through the Gunnison River. Total water bypassed around the turbines totaled 24,736 acre-feet. Forced off-peak generation at Blue Mesa and Morrow Point totaled approximately 5,700 MWh with a cost differential of $29,742. The cost to Western for the spring release from the Aspinall Units totaled approximately $110,800, which includes lost revenue from bypassed water at Crystal. Not included in this cost is the higher cost energy Western was forced to purchase for February through March 1992 when releases from Blue Mesa were backed off to save water for the release equivalent to the total amount bypassed.

The only flexibility on the system in May during the interim releases at Glen Canyon and spring peak flows at Flaming Gorge and the Aspinall Units was at Blue Mesa and Morrow Point. Scheduling contractual commitments during all three special flows was difficult to accommodate and dispatchers had little leeway to operate the power system. These spring releases are scheduled to take place for the next several years while studies proceed under the endangered fish recovery program. Operation of the SLCA/IP will be affected by the revised flows. In many cases water which was historically released during peak months will now be released in spring months when the energy and capacity has a reduced value to the power system. The flows will also restrict our ability to use installed plant capacity when needed during high contract delivery months. All restrictions placed on other SLCA/IP generation capability will affect operation at Glen Canyon.

The economy energy market remained at 17-18 mills/kWh onpeak through May 8 when a Palo Verde unit tripped and bumped the market price up to 22-23 mills/kWh for a few days. The market dropped back down to approximately 18 mills/kWh for the remainder of the month due to cool wet weather across the region. Because of the high generation on the system during May, purchases were very light. We were unable to take advantage of the reasonably priced energy on the market.

2. Power Scheduling and Purchases for the Month of June 1992

June releases from Glen Canyon were scheduled at 680,000 acre-feet. The weekday generation pattern was prescheduled to follow a 8,600 cfs (314 MW) off-peak release ramping up to a maximum-release level of 14,600 cfs (533 MW) during daytime hours for a majority of the month. The maximum daily fluctuation limit was set at 6,000 cfs (219 MW). Weekend releases were adjusted downward within criteria to follow reduced weekend loads.

Energy availability on the economy energy market was very good for the entire month of June. Prices fluctuated without any discernible reason. In the northern part of the system, on-peak power was available from 16 to 18 mills/kWh. The southern part of the system was selling energy for 23 mills/kWh for the first half of the month and then dropped to around 20 mills/kWh. Off-peak prices were between 11 to 14 mills/kWh dependent upon the week of the month. The transmission system encountered extremely high inadvertent power flows on the TOT1 system (Hayden-Vernal 138-kV and Bears Ears-Bonanza 345-kV lines) the first week of June, due to several unit outages in Utah and high schedules north by PacifiCorp. On June 1 and 2, Western was forced to violate restricted flows at Flaming Gorge to prevent that portion of the transmission system from relaying out of service. Generation from Flaming Gorge was increased from 25 MW/hr to 100 MW/hr at times to back off flows across the TOT1 path. This increased flows on the Green River from the 800-cfs restriction to 3,500 cfs at times. This is a good example of why Western needs flexibility at its individual plant to operate when different contingencies are dictated across the system. The Shiprock-Kayenta 230-kV transmission line was taken out of service on June 8 for 1 week to work on the new capacitor bank project. The power system was split north to south with Glen Canyon separated south. Dispatchers were operating the system by wheeling excess generation from Glen Canyon through Arizona and back into Colorado at Four Corners. Purchases were made to supplement deficiencies in the split regions of the system. When the system is split, operation of the power system is always more difficult. With generation at Flaming Gorge restricted, the only flexibility to shift generation due to the split came out of Blue Mesa and Morrow Point.

C. Power Scheduling Concerns for the Next Quarter

Power Scheduling Concerns for July-September 1992

All units on the SLCA/IP system will be available for generation during the summer months. Capacity commitments should not be a problem unless we lose a unit or two at Glen Canyon. Reclamation may take Morrow Point Unit No. 2 out of service in September, 2 weeks early for uprating if loads drop off. This would be a reduction of 73 MW in operating capacity. With all the restrictions on the system, a loss of 73 MW of capacity increases the exposure to system problems.

Flaming Gorge will be restricted to minimum generation (800 cfs or 25 MW/hr) until the Yampa River flows drop below 800 cfs. After that time, releases from Flaming Gorge will be increased to maintain a constant flow of approximately 1,600 cfs at the confluence of the Yampa and Green Rivers. The 800-cfs flow from Flaming Gorge is scheduled to last through the middle of July. While Flaming Gorge is restricted, the only units available to provide regulation assistance and/or follow peaks will be Morrow Point and Blue Mesa. These units will have to be closely scheduled or Glen Canyon will take all system swings related to regulation. All maintenance and/or special work on the Aspinall Unit should be coordinated well in advance with Western.

Western dispatchers will be purchasing a great deal of firming energy over the summer months during on-peak periods. It appears that there will be sufficient energy available on the interconnected system to meet our needs if the system remains healthy. Due to the low-water conditions in the Northwest, anticipated surpluses from Bonneville Power Administration (BPA) did not materialize. Energy will be available, but at higher prices.

IV. ANALYSIS OF RAMPING EVENTS

This study was made to analyze hourly ramping rates which appeared to deviate from interim flow criteria. This research was facilitated by reviewing operational records and logs kept during the study period, May 1, 1992 to June 30, 1992.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, May 1992 through June 1992 containing specific explanations for each ramping event.

Each page within the packet contains (1) a strip chart of real-time Glen Canyon Dam operations during the ramping event, (2) a graph of the USGS Lees Ferry Gauge showing river elevation during the ramping event, (3) a graph of hourly integrated Glen Canyon Dam generation during the ramping event, and (4) a brief written explanation of the ramping event.

For the study period, 38 instances of deviations were found. Most of the conditions were caused by more than one factor: for example, control area regulation and Flaming Gorge operational limitations; therefore, multiple variations can be explained by one antecedent.

The following table summarizes the causes and frequency of the 38 deviations:

	Number Of Events	Percent Of Events
Control Area Regulation or Disturbance	11/38	29
CRSP Resource Availability	9/38	24
Flaming Gorge/Aspinall Operational Limitations	5/38	13
Morrow Point Operational Limitations	1/38	3
Imports/Exports Different than Preschedule	11/38	29
Computer Trouble/Time Error Correction	1/38	3

V. EXPENSES

A. Net Expense

The net expense of interim releases for the month of May 1992 is $34,984.

This includes additional cost associated with opportunity (economy energy) sales foregone. Attached is a spreadsheet of net expense analysis for May 1992.

B. Purchases

In the change case (with interim release restrictions), the deficits are met by both purchases and the interchange received. In the base case (without interim release restrictions), all the deficits are assumed to be met by purchases. The purchases in the base case for May are approximately 41 GWh lower than that of the change case.

C. Economy Energy Sales

Economy (nonfirm) energy sales were significantly less than projected for base case conditions. A statistical analysis has been applied to calculate the nonfirm sales for the base case. Revenues foregone were estimated as $832,932 for May. Actual economy energy sales revenues for May are $119,953.

D. Purchase Prices—Base Case

Generally, purchase prices offpeak and onpeak would remain unchanged with interim release constraints. Average monthly purchase prices for May are estimated to be $14.73/MWh offpeak and $19.97/MWh onpeak.

The average monthly purchase price estimates are derived from the actual nonfirm energy purchase prices. With the help of the Power Control staff, some of the higher price purchases in May that are associated directly with interim release constraints are excluded. An adjusted weighted average of remaining purchase amounts and prices are rendered to calculate the base case offpeak and on-peak purchase prices.

E. Purchase Price—Actual

For the month of May, the base case average offpeak and on-peak purchase prices are the same as the actual average off-peak and on-peak purchase prices.

Average monthly purchase prices for actual purchases from all sources have been $14.73/MWh offpeak, and $19.97/MWh onpeak for the month of May.

F. Economy Energy Sales Prices—Base Case

Average monthly economy energy sales price for base case conditions is estimated to be $22.17/MWh for May which is the same as the actual sales price.

The estimate of economy energy sales prices involve three steps:

1. Identification of the range of market prices through review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, as reflected in Western's Weekly Reports to the Secretary.

2. Review of the actual monthly economy energy sales summary and, with the help of the Power Control staff, identify those sales directly associated with interim release constraints.

3. Assumption of expected sales price based on then-current market conditions for that portion of sales identified in step 2.

In most cases, since Western would have had the flexibility of making all or most of the nonfirm sales during the time the market has been high, with the help of the Power Control staff, the sales price for the base case is determined. However, because of the soft energy market in May, the actual and base case sales prices are the same.

G. Economy Energy Sales—Actual

The actual consummated average monthly economy energy sales price is $22.17/MWh for May.

H. Comparison, Average Purchase Prices vs Economy Energy Sales Prices

When looking at the sales prices and average purchase prices for base case and actual, we can see overall the purchase and sales prices have been consistent between the base case and actual. With the help of the Power Control staff, and review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, the base case sales prices are determined. In May, in the base case, 37,570 MWh of sales are estimated to be made with a price differential of approximately 3.93 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations 5,411 MWh of sales were made with no price differential between average sales price and average purchase price.

Glen Canyon Dam Interim Release

May 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	509,484 MWh	Firm Load & Losses:	509,484 MWh
GC Generation:	260,662 MWh	GC Generation:	260,662 MWh
Other CRSP/IP Generation:	148,324 MWh	Other CRSP/IP Generation:	148,324 MWh
Total Generation:	408,986 MWh	Total Generation:	408,986 MWh
Deficits:	103,126 MWh	Deficits:	106,162 MWh
Off Peak:	45,153 MWh	Off Peak:	22,806 MWh
On Peak:	57,973 MWh	On Peak:	83,356 MWh
Purchases:	103,126 MWh	Purchases:	143,723 MWh
Off Peak:	45,153 MWh	Off Peak:	47,641 MWh
On Peak:	57,973 MWh	On Peak:	96,082 MWh
Surplus:	3,686 MWh	Surplus:	5,664 MWh
Off Peak:	2,547 MWh	Off Peak:	2,632 MWh
On Peak:	1,139 MWh	On Peak:	3,032 MWh
Other Imports:	34,942 MWh	Other Exports:	37,814 MWh
Other Sales:	37,570 MWh	Other Sales:	5,411 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$14.73/MWh	Off Peak:	$14.73/MWh
On Peak:	$19.97/MWh	On Peak:	$19.97/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$18.24/MWh	Other Exports Price: (Avg.Purchase Price)	$22.17/MWh
Sales Price:	$22.17/MWh	Sales Price:	$22.17/MWh
Purchase Expense:	$1,822,826	Purchase Expense:	$2,620,509
Off Peak:	$665,104	Off Peak:	$701,752
On Peak:	$1,157,722	On Peak:	$1,918,758
Other Imports Expense:	$637,342	Other Exports:	$838,336
Other Sales:	$832,932	Other Sales:	$119,953
Net Expense:	$1,627,236	Net Expense:	$1,662,220

Total Net Expense for May 1992 .... $34,984

GLEN CANYON DAM INTERIM OPERATIONS

Estimated Net Expense
June-September 1992

Novmeber 1992

AREA POWER
ADMINISTRATION

TABLE OF CONTENTS

GLEN CANYON DAM INTERIM OPERATIONS

I. EXECUTIVE SUMMARY

Power Scheduling and Real-Time Operations

- From June through July energy availability was high and prices were low with onpeak prices ranging from 12-14 mills/kWh. However, in August, energy availability became tight due to high temperatures: onpeak energy prices jumped from 22 to 30 mills/kWh. In the last half of September, prices for nonfirm energy jumped from 19-20 mills/kWh to 25-36 mills/kWh during onpeak periods.

Analysis of Ramping Events

- There were 47 deviations: "Control Area Regulation" and "CRSP Resource Availability" accounted for 62% of the anomalies.

Expenses

- Net expense of interim releases:

June 1992	$247,810
July 1992	$330,358
August 1992	$519,785
September 1992	$404,643

- The net expense for FY 1992 is $2.75 million. The cumulative expense since August 1991 is $3.82 million.

The Interim Release Exception Criteria is extended through March 1993.

Power Scheduling Concerns (Future)

- Morrow Point Unit No. 2 is out of service through March 1993 for uprating activities. This is a reduction of 73 MW in operating capacity.

- It is anticipated that 850 GWh of energy will be purchased for the 1992-1993 winter season.

- Glen Canyon will be the only generation sources available for system regulation this winter due to low release levels elsewhere on our system. Hence, capacity commitments will be tight this winter.

II. INTRODUCTION

On August 1, 1991, Interior Secretary Manual Lujan implemented interim flows at Glen Canyon Dam. These interim flows were a considerable departure from previous operation of the dam and have had a significant impact on the daily operation of Western Area Power Administration's (Western) Upper Colorado Control Area.

The impacts of this sudden change in dam operations required Western to implement new scheduling procedures for its customers, develop interim release guidelines for real-time operations, purchase higher-priced energy during onpeak periods, and increase the firm-power rates to its customers to cover the additional costs.

Because these operational modifications have occurred within a brief time period, Western and its customers and the utilities interconnected within the Western network have been jolted from predictability in Western's power operations. The familiarity of daily operations established during the past 20 years has been replaced with uncertainty; however, maintaining a stable and reliable power system operating within the constraints of the Upper Colorado River Basin Fund remains unchanged.

Since their inceptions, Western and the Bureau of Reclamation (Reclamation) have been successful in meeting the operational parameters of interim flows. Several refinements such as the 24-hour rolling period, the 30-day rolling period, and regulation caused minor problems. Once these issues were resolved by the Cooperating Agencies, Western and Reclamation responded in kind.

The following sections are a review of Power Operations for the reporting period.

III. SCHEDULING

A. General Scheduling Procedures Under Interim Release Operations

Scheduling procedures associated with the delivery of Salt Lake City Area Integrated Projects (SLCA/IP) firm capacity and energy have been modified to accommodate the release restrictions imposed on Glen Canyon Powerplant with interim release constraints.

Under previous scheduling procedures, SLCA/IP contractors were allowed to preschedule their monthly capacity allocations on an hourly basis, within established minimum and/or maximum schedule limits set by contract. Energy is delivered under the capacity up to the contractors' monthly energy entitlements as defined in Exhibit A of their electric service contracts. Capacity and associated energy schedules could have been changed (real-time) to adjust to changes in system load.

Interim release restrictions have limited Western's ability to accommodate hourly changes in the preschedules. These restrictions have required Western to request customer prescheduling 3 days in advance in order to match firm loads to available project resources and substitute purchases for any hourly deficits. Hourly changes to preschedules have been restricted by the lack of system flexibility. The burden to adjust to changes in real-time load has shifted from the contractors' use of their SLCA/IP resources to the contractors' alternate resources. A majority of these other resources are thermal and have higher costs in their use.

After Western receives the contractors' advance firm schedules, project generation is patterned hourly to optimize system capacity. During times of surplus generation, the surplus is scheduled when the energy reaches its greatest value. In times of hourly deficiencies, unit capacity is scheduled over system peaks to the maximum available, and hourly shortages are met through nonfirm energy purchases.

During periods of normal operations, there were no hourly deficiencies due to restricted flows from Glen Canyon. System energy shortages were supplied through nonfirm purchases scheduled in equal amounts across all hours, divided into onpeak and offpeak periods. Hourly peaks were covered with available project capacity.

Under interim operations, Western must determine when the system peak loads will occur and purchase nonfirm energy to cover shortages during specific hours, requiring advance scheduling of both project generation and nonfirm purchases. Due to the very narrow ramping restrictions at Glen Canyon, offpeak generation has been increased and energy, normally purchased offpeak when generation was low, is purchased during higher priced onpeak periods.

Interim release conditions have forced scheduling and dispatch personnel to monitor projected water releases and hourly generation levels very carefully.

With interim release conditions, Glen Canyon Dam Powerplant must operate within very specific daily fluctuation limits. Peaking capacity required to serve firm load obligations unavailable at Glen Canyon must be obtained from other project resources. These resources have daily water limitations which must be maintained. Any large deviations from anticipated generation levels which may occur on a real-time basis could affect prescheduling for several days. To avoid this, a very comprehensive set of interim release guidelines have been developed for dispatchers to use when running the power system during real-time operations. One individual is solely devoted to coordinate prescheduling with dispatch. Not surprisingly, this new set of procedures brought on by Interim Flow restrictions complicate "normal" Glen Canyon operations.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for June 1992

June releases from Glen Canyon were scheduled at 680,000 acre-feet. The weekday generation pattern was prescheduled to follow a 8,600 cfs (314 MW) offpeak release ramping up to a maximum-release level of 14,600 cfs (533 MW) during daytime hours for a majority of the month. The maximum daily fluctuation limit was set at 6,000 cfs (219 MW). Weekend releases were adjusted downward within criteria to follow reduced weekend loads.

Energy availability on the economy energy market was very good for the entire month. Prices fluctuated without any discernible reason. In the northern part of the system, onpeak power was available from 16 to 18 mills/kWh. The southern part of the system was selling energy for 23 mills/kWh for the first half of the month and then dropped to around 20 mills/kWh. Offpeak prices were between 11 to 14 mills/kWh dependent upon the week of the month. Average purchase prices have been $14.97/MWh offpeak and $20.18/MWh onpeak. The total purchases in June was 134,943 MWh.

The transmission system encountered extremely high inadvertent power flows on the TOT1 system (Hayden-Vernal 138-kV and Bears Ears-Bonanza 345-kV lines) the first week of June due to several unit outages in Utah and high schedules north by PacifiCorp.

On June 1 and 2, Western was forced to violate restricted flows at Flaming Gorge to prevent that portion of the transmission system from relaying out of service. Generation from Flaming Gorge was increased from 25 MW/hr to 100 MW/hr at times to back off flows across the TOT1 path. This increased flows on the Green River from the 800-cfs restriction to 3,500 cfs at times. This is a good example of why Western needs flexibility at its individual plant to operate when different contingencies are dictated across the system.

The Shiprock-Kayenta 230-kV transmission line was taken out of service on June 8 for 1 week for work on the new capacitor bank project. The power system was split north to south with Glen Canyon separated south. Dispatchers were operating the system by wheeling excess generation from Glen Canyon through Arizona and back into Colorado at Four Corners. Purchases were made to supplement deficiencies in the split regions of the system. When the system is split, operation of the power system is always more difficult. With generation at Flaming Gorge restricted, the only flexibility to shift generation due to the split came out of Blue Mesa and Morrow Point.

2. Power Scheduling and Purchases for July 1992

July releases from Glen Canyon were scheduled at 870,000 acre-feet. The weekday generation pattern was prescheduled at 10,800 cfs (398 MW) during offpeak hours ramping up to a maximum of 18,800 cfs (694 MW) during onpeak hours for a majority of the month. This follows the daily maximum fluctuation restriction of 8,000 cfs (296 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

July was an unusual month on the SLCA/IP power system. Historically, this is a peak month on the power system which causes economy energy prices to rise and energy availability to drop. This year, peak loads did not develop due to cool weather conditions across the region. The Northern States (i.e., North and South Dakota, Minnesota, Montana) had very cool weather conditions. Energy availability from the Northern States was very high and prices were extremely low (onpeak: 12-14 mills/kWh). The combination of higher Glen Canyon releases and the low energy prices allowed Western to keep purchased energy costs down. The average purchase price was $13.71/MWh for offpeak and $20.32/MWh for onpeak. The total purchases for July 1992 was 128,795 MWh.

No unusual events occurred on the system in July. Construction activities continued on the Kayenta capacitor banks, and the Shiprock-Kayenta 230-kV line was placed out of service which split the system. Glen Canyon generation was separated from the Northern system which presented some real time scheduling difficulties. Flaming Gorge generation was restricted to a fluctuation band of 1,350 cfs to 1,800 cfs This fluctuation band limited generation capability to a few megawatts from a constant 26 MW generation level. The Aspinall Units were solely available to meet load requirements.

3. Power Scheduling and Purchases for August 1992

August releases from Glen Canyon totaled 876,000 acre-feet. The weekday generation pattern was prescheduled at 10,700 cfs (393 MW) during offpeak hours ramping up to a maximum of 18,700 cfs (696 MW) during onpeak hours for a majority of the month. This follows the daily maximum fluctuation restriction of 8,000 cfs (303 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

Weather in the beginning of August was cool and moist; the economy energy market remained soft through the middle of the month. By mid-August temperatures turned hot in the Southwest driving energy availability down; therefore, economy energy prices went up from 22 mills/kWh to approximately 30 mills/kWh during onpeak periods. However, high release levels at Glen Canyon and Western's long term energy contracts prevented Western being affected by this jump in the market. August purchase prices was $15.33/MWh for offpeak and $22.04/MWh for onpeak. Total purchase for August 1992 was 116,417 MWh.

Construction activities continued on the Kayenta capacitor banks. The Shiprock-Kayenta 230 kV line was placed out of service which split the system. Flaming Gorge generation was restricted to a fluctuation band of 1,350 cfs to 1,800 cfs. This fluctuation band limited generation capability to a few megawatts from a constant 26 MW generation level. The Aspinall Units were solely available to meet load requirements.

4. Power Scheduling and Purchases for September 1992

September releases from Glen Canyon totaled 732,000 acre-feet. The weekday generation pattern was prescheduled at 9,000 cfs (328 MW) during offpeak hours ramping up to a maximum of 15,000 cfs (547 MW) during onpeak hours for a majority of the month. Daily releases were reduced gradually towards the end of the month to meet 8.23 MAF water release limit. Weekend releases were adjusted downward to follow reduced weekend loads.

In the first two weeks of September energy availability was good and firm load was met through seasonal and long term contracts. A few contractors who had anticipated planned unit outages for late in the month, saved their energy entitlements. However, this action caused problems for Western's firm load obligations later in the month when loads increased and the economy energy market became tight. Obviously, if Western had the opportunity to store water at Glen Canyon for later release in the month, it would not have been forced to release water when it was less valuable and forced to make purchases at high prices. Prices for nonfirm energy increased from 19-20 mills/kWh to 25-36 mills/kWh during onpeak periods. Prices remained high from September 18 through the end of the month.

Flaming Gorge generation was reduced to constant minimum stream flows to 8,000 cfs (26 MW) on September 15. The Aspinall Units were the only units available to meet load requirements.

<u>Power Scheduling Concerns for October 1992-March 1993</u>.

Flaming Gorge generation will be limited to a minimum of 800 cfs (26 MW) through the Winter. Morrow Point Unit No. 2 is out of service through March 1993 for uprating activities. This is a reduction of 73 MW in operating capacity. However, if current system conditions are maintained, this should not create an operational problem. Glen Canyon will be the only generation sources available for system regulation this winter due to low release levels elsewhere on our system. Hence, capacity commitments will be tight but should not be a problem unless there are unit outages at Glen Canyon. Some unit maintenance was rescheduled to accommodate capacity shortages in January and February.

Summer season runoff into the CRSP system was much lower than anticipated. This condition has forced Reclamation to reduce the amount of water to be released from the Aspinall Units during the winter season. With Flaming Gorge unavailable for load purposes, Western was relying on the Aspinall Units for regulation assistance and reducing the need for high energy purchases over peak hours. With reduced water, the Aspinall Units will be available for approximately 6 to 7 hours of operation daily at a very low load factor. This will place the burden for all regulation and system swings on Glen Canyon this winter.

Purchases will be extremely high which is normal for a winter season. Onpeak purchases will be as much as 350 MW/hr. and will be scheduled to fit the customer load pattern. We are anticipating the need to purchase approximately 850 GWh of energy this winter season. Prices will be much higher this winter because a good portion of the energy will be contracted in advance for the 6-month period with less energy purchased on the economy energy market.

IV. ANALYSIS OF RAMPING EVENTS

This study was made to analyze hourly ramping rates which appeared to deviate from interim flow criteria. This research was facilitated by reviewing operational records and logs kept during the study period, July 1, 1992, through September 30, 1992.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, for July through September 1992 containing specific explanations for each ramping event.

Each page within the packet contains (1) a strip chart of real-time Glen Canyon Dam operations during the ramping event, (2) a graph of the USGS Lees Ferry Gauge showing river elevation during the ramping event, (3) a graph of hourly integrated Glen Canyon Dam generation during the ramping event, and (4) a brief written explanation of the ramping event.

For the study period, 47 instances of deviations were found. Most of the conditions were caused by more than one factor: for example, control area regulation and CRSP resource availability; therefore, multiple variations can be explained by one antecedent.

The following table summarizes the causes and frequency of the 47 deviations:

Primary Cause(s) of Deviation	Number Of Instances	Percent Of Events
Control Area Regulation	16/47	34
CRSP Resource Availability	13/47	28
Aspinall Operations	9/47	19
Imports/Exports Different than Preschedule	7/47	15
Morrow Point	3/47	6
Other	8/47	17

V. EXPENSES

A. Net Expense

The net expense of interim releases for June, July, August, and September 1992 are summarized below:

	Net Expense
June 1992	$247,810
July 1992	$330,358
August 1992	$519,785
September 1992	$404,643

The next expense for FY 1992 is $2,757,942. The cumulative net expense since August 1992 is $3,823,634.

This includes additional cost associated with opportunity (economy energy) sales foregone. Attached are Tables 1-4 of net expense analysis for June and July, August, and September 1992.

Previously, all seven days of the week were considered as weekdays. Every Sunday was treated no differently than the other week days. Now in this analysis for August and September, all of Sunday was considered as offpeak hours.

B. Purchases

In the change case (with interim release restrictions), the deficits are met by both purchases and the interchange received. In the base case (without interim release restrictions), all the deficits are assumed to be met by purchases. The purchases in the base case for June are approximately 8 GWh higher than that of the change case. In July, the base case purchases are nearly 12 GWh lower than that of the change case. In August, the base case purchases are nearly 1.4 GWh higher than that of the change case. In September, the base case purchases are nearly 1.4 GWh lower than that of the change case.

C. Economy Energy Sales

Economy (nonfirm) energy sales were less than projected for base case conditions. A regression analysis has been applied to calculate the nonfirm sales for the base case. Revenues foregone were estimated at $742,424 for June, $695,923 for July, $751,060 for August, and $824,761 for September. Actual economy energy sales revenues for June, July, August, and September are $251,655, $497,161, $238,017, and $240,679 respectively.

D. Purchase Prices—Base Case

Generally, purchase prices offpeak and onpeak would remain unchanged with interim release constraints. Average monthly purchase prices are estimated as follows:

Months	Offpeak	Onpeak
June 1992	$14.97/MWh	$20.18/MWh
July 1992	$13.70/MWh	$20.24/MWh
August 1992	$15.20/MWh	$21.49/MWh
September 1992	$15.47/MWh	$23.21/MWh

The average monthly purchase price estimates are derived from the actual nonfirm energy purchase prices. With the help of the Power Control staff, some of the higher price purchases in July, August, and September that are associated directly with interim release constraints are excluded. An adjusted weighted average of remaining purchase amounts and prices are rendered to calculate the base case offpeak and onpeak purchase prices. In July, August and September the actual and base case purchase prices differ due to the deletion of some purchases that were considered too high by the Power Control Staff.

E. Purchase Price—Actual

The June base case average offpeak and onpeak purchase prices are the same as the actual average offpeak and onpeak purchase prices. Average actual monthly purchase prices from all sources are as follows:

Months	Offpeak	Onpeak
June 1992	$14.97/MWh	$20.18/MWh
July 1992	$13.71/MWh	$20.32/MWh
August 1992	$15.33/MWh	$22.04/MWh
September 1992	$15.47/MWh	$23.51/MWh

F. Economy Energy Sales Prices—Base Case

Average monthly economy energy sales price for base case conditions is estimated to be $23.31/MWh for June, $23.58/MWh for August, and $24.38/MWh for September which is the same as the actual sales price.

For July, average monthly economy energy sales prices for base conditions is estimated to be $21.85/MWh.

The estimate of economy energy sales prices involve three steps:

1. Identification of the range of market prices through review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, as reflected in Western's Weekly Reports to the Secretary.

2. Review of the actual monthly economy energy sales summary and, with the help of the Power Control staff, identify those sales directly associated with interim release constraints.

3. Assumption of expected sales price based on then-current market conditions for that portion of sales identified in step 2.

In most cases, since Western would have had the flexibility of making all or most of the nonfirm sales during the time the market has been high, with the help of the Power Control staff, the sales price for the base case is determined. Because of the soft energy market in June the actual and base case sales prices are the same. In July, the actual and base case sales prices differ due to the deletion of some nonfirm sales that were deemed too low by the Power Control staff. In August and September there were no forced sales.

G. Economy Energy Sales—Actual

The actual consummated average monthly economy energy sales price is:

June 1992	$23.31/MWh
July 1992	$20.56/MWh
August 1992	$23.58/MWh
September 1992	$24.38/MWh

H. Comparison, Average Purchase Prices vs Economy Energy Sales Prices

When looking at the sales prices and average purchase prices for base case and actual, overall, the purchase and sales prices have been consistent between the base case and actual. With the help of the Power Control staff and review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, the base case sales prices are determined.

In the June base case, 31,850 MWh of sales are estimated to be made with a price differential of approximately 4.29 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations, 10,796 MWh of sales were made with the same price differential of 4.29 mills/kWh.

In the July base case, 31,850 MWh of sales are estimated to be made with a price differential of 2.45 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations, 24,181 MWh of sales were made with a price differential of 1.08 mills/kWh.

In the August base case, 31,852 MWh of sales are estimated to be made with a price differential of 5.78 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations, 10,094 MWh of sales were made with a price differential of 2.64 mills/kWh.

In the September base case, 33,829 MWh of sales are estimated to be made with a price differential of 5.55 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations, 9,872 MWh of sales were made with a price differential of 2.95 mills/kWh.

November 1992

Table 1
Glen Canyon Dam Interim Release
for June 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	562,438 MWh	Firm Load & Losses:	562,438 MWh
GC Generation:	300,564 MWh	GC Generation:	300,564 MWh
Other CRSP/IP Generation:	118,979 MWh	Other CRSP/IP Generation:	118,979 MWh
Total Generation:	419,543 MWh	Total Generation:	419,543 MWh
Deficits:	142,893 MWh	Deficits:	142,940 MWh
Off Peak:	62,142 MWh	Off Peak:	28,727 MWh
On Peak:	80,751 MWh	On Peak:	114,213 MWh
Purchases:	142,893 MWh	Purchases:	134,943 MWh
Off Peak:	62,142 MWh	Off Peak:	30,034 MWh
On Peak:	80,751 MWh	On Peak:	104,909 MWh
Surplus:	0 MWh	Surplus:	45 MWh
Off Peak:	0 MWh	Off Peak:	0 MWh
On Peak:	0 MWh	On Peak:	45 MWh
Other Imports:	31,852 MWh	Other Imports:	18,718 MWh
Other Sales:	31,850 MWh	Other Sales:	10,796 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$14.97/MWh	Off Peak:	$14.97/MWh
On Peak:	$20.18/MWh	On Peak:	$20.18/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$19.02/MWh	Other Imports Price: (Avg.Purchase Price)	$19.02/MWh
Sales Price:	$23.31/MWh	Sales Price:	$23.31
		Other Exports Price:	$23.31/MWh
Purchase Expense:	$2,559,820	Purchase Expense:	$2,566,673
Off Peak:	$930,260	Off Peak:	$449,609
On Peak:	$1,629,560	On Peak:	$2,117,064
Other Imports Expense:	$605,828	Other Imports:	$356,016
Other Sales:	$742,424	Other Sales:	$251,655
Base Case Expense:	$2,423,224	Change Case Expense:	$2,671,034

Total Net Expense for June 1992 .... **$247,810**

November 1992

Table 2
Glen Canyon Dam Interim Release
for July 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	634,367 MWh	Firm Load & Losses:	634,367 MWh
GC Generation:	387,808 MWh	GC Generation:	387,808 MWh
Other CRSP/IP Generation:	130,233 MWh	Other CRSP/IP Generation:	130,233 MWh
Total Generation:	518,041 MWh	Total Generation:	518,041 MWh
Deficits:	116,325 MWh	Deficits:	117,178 MWh
Off Peak:	56,215 MWh	Off Peak:	7,102 MWh
On Peak:	60,110 MWh	On Peak:	110,076 MWh
Purchases:	116,325 MWh	Purchases:	128,795 MWh
Off Peak:	56,215 MWh	Off Peak:	16,488 MWh
On Peak:	60,110 MWh	On Peak:	112,307 MWh
Surplus:	0 MWh	Surplus:	852 MWh
Off Peak:	0 MWh	Off Peak:	297 MWh
On Peak:	0 MWh	On Peak:	555 MWh
Other Imports:	31,851 MWh	Other Imports:	11,712 MWh
Other Sales:	31,850 MWh	Other Sales:	24,181 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$13.70/MWh	Off Peak:	$13.71/MWh
On Peak:	$20.24/MWh	On Peak:	$20.32/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$19.40/MWh	Other Imports Price: (Avg.Purchase Price)	$19.48/MWh
Sales Price:	$21.85/MWh	Sales Price:	$20.56
		Other Exports Price:	$20.56/MWh
Purchase Expense:	$2,171,086	Purchase Expense:	$2,508,129
Off Peak:	$842,661	Off Peak:	$226,050
On Peak:	$1,328,425	On Peak:	$2,282,078
Other Imports Expense:	$678,754	Other Imports:	$228,150
Other Sales:	$695,923	Other Sales:	$497,161
Base Case Expense:	$2,153,917	Change Case Expense:	$2,239,117

Total Net Expense for July 1992 .... **$330,358**

November 1992

Table 3
Glen Canyon Dam Interim Release
August 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	634,270 MWh	Firm Load & Losses:	634,270 MWh
GC Generation:	385,004 MWh	GC Generation:	385,006 MWh
Other CRSP/IP Generation:	134,209 MWh	Other CRSP/IP Generation:	134,209 MWh
Total Generation:	519,213 MWh	Total Generation:	519,215 MWh
Deficits:	115,058 MWh	Deficits:	115,451 MWh
Off Peak:	67,474 MWh	Off Peak:	18,859 MWh
On Peak:	47,585 MWh	On Peak:	96,592 MWh
Purchases:	115,058 MWh	Purchases:	116,417 MWh
Off Peak:	67,474 MWh	Off Peak:	18,945 MWh
On Peak:	47,585 MWh	On Peak:	97,472 MWh
Surplus:	1 MWh	Surplus:	396 MWh
Off Peak:	0 MWh	Off Peak:	396 MWh
On Peak:	1 MWh	On Peak:	0 MWh
Other Imports:	31,835 MWh	Other Imports:	8,732 MWh
Other Sales:	31,852 MWh	Other Sales:	10,094 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$15.20/MWh	Off Peak:	$15.33/MWh
On Peak:	$21.49/MWh	On Peak:	$22.04/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$17.80/MWh	Other Imports Price: (Avg.Purchase Price)	$20.94/MWh
Sales Price:	$23.58/MWh	Sales Price:	$23.58
		Other Exports Price:	$23.58/MWh
Purchase Expense:	$2,047,811	Purchase Expense:	$2,438,269
Off Peak:	$1,025,363	Off Peak:	$290,409
On Peak:	$1,022,448	On Peak:	$2,147,860
Other Imports Expense:	$566,601	Other Imports:	$182,885
Other Sales:	$751,060	Other Sales:	$238,017
Base Case Expense:	$1,863,352	Change Case Expense:	$2,383,137

Total Net Expense for August 1992 .... $519,785

Table 4
Glen Canyon Dam Interim Release
for September 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:519,947 MWh		Firm Load & Losses:519,947 MWh	
GC Generation:	315,886 MWh	GC Generation:	315,886 MWh
Other CRSP/IP Generation:	109,304 MWh	Other CRSP/IP Generation:	109,304 MWh
Total Generation:	425,190 MWh	Total Generation:	425,190 MWh
Deficits:	96,030 MWh	Deficits:	94,829 MWh
Off Peak:	54,343 MWh	Off Peak:	24,706 MWh
On Peak:	41,687 MWh	On Peak:	70,123 MWh
Purchases:	96,030 MWh	Purchases:	94,653 MWh
Off Peak:	54,343 MWh	Off Peak:	24,493 MWh
On Peak:	41,687 MWh	On Peak:	70,160 MWh
Surplus:	1,273 MWh	Surplus:	72 MWh
Off Peak:	187 MWh	Off Peak:	59 MWh
On Peak:	1,086 MWh	On Peak:	13 MWh
Other Imports:	32,556 MWh	Other Imports:	9,966 MWh
Other Sales:	33,829 MWh	Other Sales:	9,872 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$15.47/MWh	Off Peak:	$15.47/MWh
On Peak:	$23.21/MWh	On Peak:	$23.51/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$18.83/MWh	Other Imports Price: (Avg.Purchase Price)	$21.43/MWh
Sales Price:	$24.38/MWh	Sales Price:	$24.38
		Other Exports Price:	$24.38/MWh
Purchase Expense:	$1,808,414	Purchase Expense:	$2,028,484
Off Peak:	$840,732	Off Peak:	$378,929
On Peak:	$967,682	On Peak:	$1,649,555
Other Imports Expense:	$613,088	Other Imports:	$213,579
Other Sales:	$824,761	Other Sales:	$240,679
Base Case Expense:	$1,596,741	Change Case Expense:	$2,001,384

Total Net Expense for September 1992 .... **$404,643**