GLEN CANYON DAM INTERIM OPERATIONS

Western Area Power Administration

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WESTERN
AREA POWER ADMINISTRATION

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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 <u>increasing regulation and system swing pressure on Glen Canyon</u>.

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. <u>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.</u> 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. <u>Scheduling contractual commitments during all three special flows was difficult to accommodate and dispatchers had little leeway to operate the power system</u>. 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. <u>All restrictions placed on other SLCA/IP generation capability will affect operation at Glen Canyon</u>.

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