9

Reservoir Operations

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INTRODUCTION

What is a reasonable structure for a set of models for the Glen Canyon Dam (GCD) operation problem. The system appears to require at least two types of model: (1) a reservoir hydrology model with monthly time steps and (2) a model of releases with hourly time steps to capture the hourly variation in value of hydropower and to characterize downstream flows—input to a routing model or to other models for environmental parameters that are affected by diurnal flow and ramping rates. Modeling explicitly flows or energy every hour for a period of several years is possible but not very useful, because the results are impossible to interpret except in the form of a statistical summary. Thus, the conventional approach to providing input to the parameters of such a very short term energy model is the excedance curve (basically a cumulative distribution function [CDF]) representing the fraction of time for which a parameter is greater or less than a selected level. There are pitfalls that often distort analysis of systems using the excedance approach. One is related to errors introduced by averaging (to be demonstrated later). A second source of error is the loss of ability to model head on turbines explicitly.

An oversimplified but useful graphic representation of the approaches used to date to model the GCD operation is given in Figure 9-1.

Since much of the flow into Lake Powell is regulated by several upstream reservoirs, the initial hydrograph shown in Figure 9-1 represents

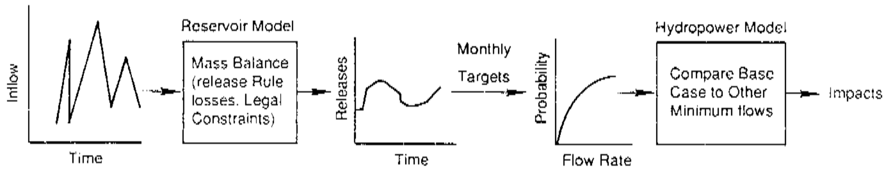


FIGURE 9-1 Relationship of hydrology and energy models.

either historic data or output from a large multireservoir operation model, which is not shown.

The reservoir simulation model converts reservoir inflow data into a trace of time-related releases (for which storage, and therefore water level, in the reservoir is explicitly known). The short-term model converts this trace into an excedance function, thereby losing the ability to associate correct heads with flows. It is therefore necessary to select a single (average) value of head for the entire analysis (usually a year) to translate flow rates into energy and/or power. This is not a serious problem for normal operation of GCD because the variation of water level over a year is usually only about 5% of the total; in a drought year, however, it can approach 10%.

ANNUAL OPERATION WITH MONTHLY TIME STEPS

The USBR Reservoir Model

The Colorado River Storage Project (CRSP) is a multireservoir system. GCD is the downstream end of the system; upstream reservoirs include Flaming Gorge, Fontanelle, Navajo, Crystal, Blue Mesa, and Morrow Point. GCD, however, represents 79% of the storage capacity and 78% of the generating capacity of CRSP. One hundred percent of the upper Colorado flows (except for the small Pariah) pass GCD.

About half of the flow into Lake Powell is unregulated, and half is a function of the operating rules at the other upper basin reservoirs. Lake Mead is the only downstream reservoir that should be considered in a model of the operation of GCD, and the only reason for including this reservoir is a politically imposed constraint that at the beginning of each water year, the storage intake of Lake Powell cannot exceed that in Lake Mead. From the perspective of comprehensive river basin planning, this constraint is not a wise policy. One of the basic tenets of good multireservoir system operation is that one always keeps as much of the water as possible as high in the system as possible for as long as possible (within reasonable flood control criteria), because water can always quickly be moved to a lower reservoir as needed but can never be moved back if a mistake is made. The reason that this constraint was imposed in this case has to do with upper and lower basin politics and who has control of subsystems rather than total system operating efficiency.

A simulation model of the entire river called CRSS has been developed by the U.S. Bureau of Reclamation (USBR) (Schuster 1987, 1988a,b). The model structure appears to be totally adequate for the monthly time step hydrologic analysis required for the GCES program. There should, however, be a detailed review of the demand input data base (SMDDID) in regard to updating the assumptions on the level of future upper basin diversions from the river. Past assumptions on the timing and extent of development of upper basin projects are undoubtedly obsolete, given the major cutback in federal funding of future projects.

The principal losses of water from Lake Powell are evaporation and bank storage. Average annual evaporation depths from Lake Powell have been estimated by the RANN research program at 70 inches (Potter and Drake, 1989) and by Hughes et al. (1974) at 68 inches. Evaporation, of course, varies significantly with climatic variations, but the expected value must be used in a planning model since the climate cannot be forecast. The RANN estimate is probably best, since it was determined by actual pan measurements located on the lake. Evaporation from the upper basin reservoirs during typical years (when Lake Powell was almost full and had an average surface area of 156,000 acres) was estimated by the CRSS model as 0.73 million acre-feet (maf) (0.61 maf in Lake Powell and 0.12 total maf in other reservoirs). The 0.61 maf figure implies a depth of only 47 inches. The difference between 70 and 47 inches is too much to be explained as a correction for rainfall (about 6 inches per year), which now falls directly on the lake but used to be mostly lost to evapo-transpiration within the area inundated. It therefore appears that the CRSS model underestimates evaporation by about 24%.

As more data become available on reconciliation of theoretical versus actual mass balance of parameters in the reservoir and releases from GCD versus flows at Lee's Ferry, the way in which bank storage in Lake Powell is modeled should be improved. The current practice of estimating it as 8% of the change in storage regardless of water level was previously necessary because no empirical data were available in the early years of operation to justify a better approach. This parameter, however, represents about 8 maf of water (Potter and Drake, 1989) and should be given more attention now that some 25 years of operation data are available. This factor is not important during cycles of close to normal or wet years when the reservoir fills each July, but during an extended drought, bank storage would become a very important asset (and also an important liability in slowing refilling of the reservoir after a drought).

Various hydrologic data bases are used for long-term planning studies by CRSS. The data, which began in 1906 and continues to date, include: (1) virgin flows, i.e., data modified to remove the estimated effect of diversions and reservoir regulation, and (2) depleted flows, i.e., data modified to simulate flows as if no reservoirs exist (and therefore evaporation is not part of the depletion). Depletions at current levels are imposed over the entire period of record in this data base. The effects of reservoir regulation, evaporation, and bank storage are functions of the reservoir operating rule and therefore cannot be included in the data bases.

Modes of Operation for CRSS

Uses of the CRSS model depend on the objective of the user. Long-term planning studies use the entire 80-year data base for determining statistical properties of the hydrology, frequency of floods and droughts, etc., and may also develop synthetic hydrologic sequences of flows. The real-time operation problem, however, uses a different version of the model to predict state of the system 24 months into the future. Although this model exists on a mainframe computer at the USBR Denver Research Center, a microcomputer version of the 24-month planning model has been developed by the Upper Colorado River Commission (1987) in Salt Lake City, using only a spreadsheet.

Other Reservoir Models

Another simulation model of the Colorado River that has received some attention in the literature was developed jointly by the Rocky Mountain Forest and Range Experiment Station and WBLA, Inc. (Brown et al., 1988, 1989). This model uses software developed originally for the Texas Water Resource Planning Agency. It has since been used extensively by researchers at Colorado State University. The essential difference between this model and the CRSS model is that the WBLA model has a within-month optimization algorithm which allocates water during a particular month in a way that maximizes an economic objective (dollars per acre-foot in various uses) subject to the river compacts and other statutory priorities on releases. This model should not be confused with an optimization model that optimizes releases over a planning horizon such as a year. The optimization is only on allocation among users within any month. The determination of releases, for example in July versus May, is done in a simulation framework (same as the CRSS model), which is to say that the monthly operating rule is assumed, not optimized as it would be by using a linear decision rule or a dynamic programming model.

Who Operates the Dam?

The simple and realistic answer to this question is: USBR determines monthly (and therefore annual) releases, and the Western Area Power Administrtion (WAPA) operates the dam in real time, subject to meeting the USBR monthly targets. The official answer to this question contains a long list of caveats about coordination with other interested parties. Since the embarrassing flood damage of 1983, this coordination has taken the form of a Colorado River Management Work Group chaired by USBR and consisting of representatives from each state, the Upper Colorado River Commission, and WAPA. Barry Saunders (the Utah representative) reports: "For over five years, the seven-state Governor's representatives (and Management Work Group) have been functioning with increasing efficiency in balancing water supply and flood control requirements. To date the process has not been utilized effectively for addressing environmental issues" (Saunders, 1989).

USBR Operating Plan

Glen Canyon Dam (along with all other dams in the upper basin) is operated by using information derived from a 24-month operating period version of the CRSS model. Each run of the model includes the last 12 months plus a monthly projection for the next 24 months. Releases are conditioned in the near term (the snowmelt season) on both water content of the snow and antecedent precipitation (a surrogate for soil moisture conditions). Projections for the second year are presumably based on expected values. The current USBR approach to determining future releases is not an explicit one, such as would be obtained from a linear decision rule, but rather is a heuristic approach developed by considering both an optimistic and a pessimistic range of runoff from current snowpack and observing the resulting range of storage results. The procedure is then repeated monthly, and projected flows are updated by using actual current storage and revising future inflow estimates conditioned upon current snowpack conditions. The magnitude of typical correction to original projections needed during a drought period is shown in Figure 9-2, which displays the initial projection and the final measured releases from GCD for the USBR 2-year projection of monthly releases during calendar years 1988 and 1989. The variations by no means indicate deficiencies in the operating rule but rather display the degree of hydrologic uncertainty facing the planner.

An oversimplified description of the criteria used to determine the annual release targets is as follows.

Annual Release at Lee's Ferry — Only the 8.23-maf average minimum required by the compact plus the Mexican treaty will be released unless

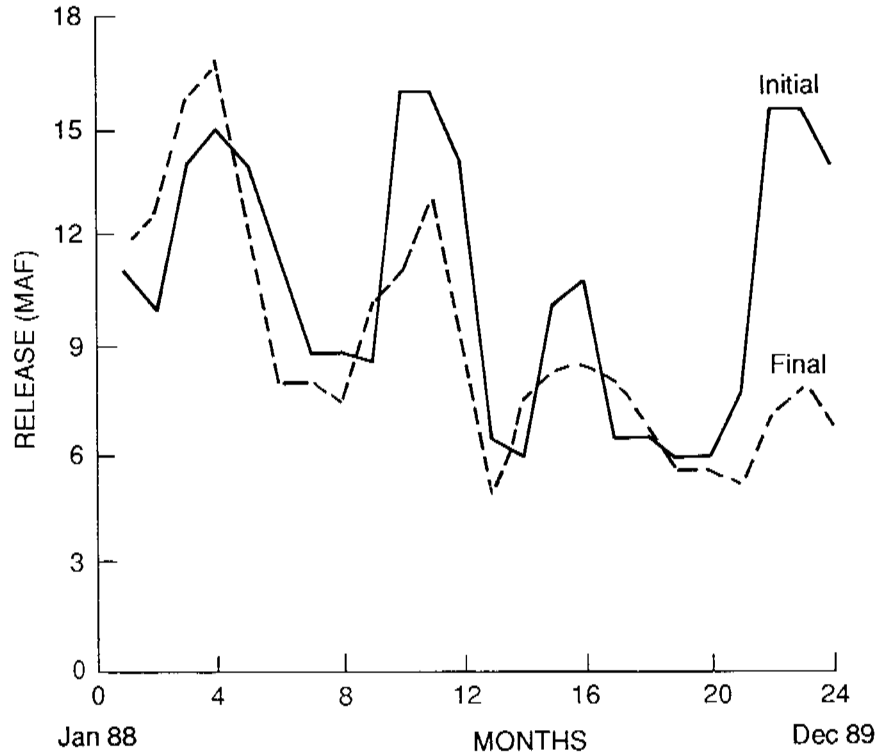


FIGURE 9-2 Variation from the initial to final operating plan.
SOURCE: USBR, 1989.

there is a significant probability of spills during the next runoff season. In this context, spills are defined as flows that bypass the turbines.

Monthly Target Releases — Within a year, the monthly targets are allocated to create a flood storage space of 2.4 maf on January 1 and to be within 0.5 maf of full by July 1. Prior to 1983, the July target was a totally full reservoir (25 maf of active storage above the river outlets), but the 0.5 compromise was recently agreed upon by the operations management group. The USBR statistical analysis of the hydrology concludes that this change will decrease the probability of a spill from .25 to .05.

Where possible, the monthly targets are also shaped to improve the ability of WAPA to better follow the seasonal peaks and valleys in energy demand. For example, targets in winter and in summer are somewhat greater than those in spring and fall. These fluctuations, however, are much less extreme than the daily fluctuations to be discussed later (they typically vary from 0.5 to 1.0 maf, and some of this variation is due to flood/conservation balancing rather than energy considerations.

There is no reason to shape monthly releases from GCD to follow the seasonal irrigation pattern of releases in the lower basin because Lake Mead can regulate such variations. The only exception to this is the requirement to not exceed the Lake Mead storage at the end of the water year (September 30).

SHORT-TERM OPERATION OF THE DAM

For the monthly hydrology model discussed above, it was necessary to draw the system boundary around the entire upper basin. Given the output of that model, however, a smaller boundary is adequate for the short term model. Hourly releases from upstream reservoirs are totally redundant for modeling GCD releases necessary to capture the impact of revised minimum instantaneous flow rates. Also, monthly release targets (the USBR operation decisions) that are both feasible and desirable are essentially independent of minimum flow rates (the WAPA operating decisions). If flows at night are increased, daytime flows must be decreased to still meet the monthly target. There are, of course, minimum release criteria which would be infeasible. For example, a monthly target of 0.5 maf is a constant flow of 8,300 cubic feet per second (CFS). Clearly, a higher minimum release would be infeasible. Increases in minimum flows have no effect on total hydropower generated because the same volume of water at the same head (except for minor changes in backwater levels) passes the turbines by the end of a month. Either this volume will equal the monthly target or any deviation from the target can be corrected early in the subsequent month. Only the value, not the quantity, of energy is changed by the minimum flow criteria.

Short-term models of reservoir releases and their translation into energy are traditionally done in terms of excedance functions or CDFs (the probability of flow exceeding any given level) as opposed to the monthly hydrologic model, which captures sequentially for each time step the mass balance of inflow and outflow from a system. Therefore, it is therefore appropriate to discuss the implications of this modeling approach. In interpreting such information, it is important to know both the time step of input data used to generate the excedance function and also what averaging was done before the CDF was developed. Consider the peak period and off-peak period CDFs in Figure 9-3. These excedance curves were developed from hourly data for the 13 years since the lake approached a normal operating mode (1978-1989). They indicate that release rates are below 5,000 and 8,000 cfs 30 and 47% of the time, respectively, during hours when energy is at low

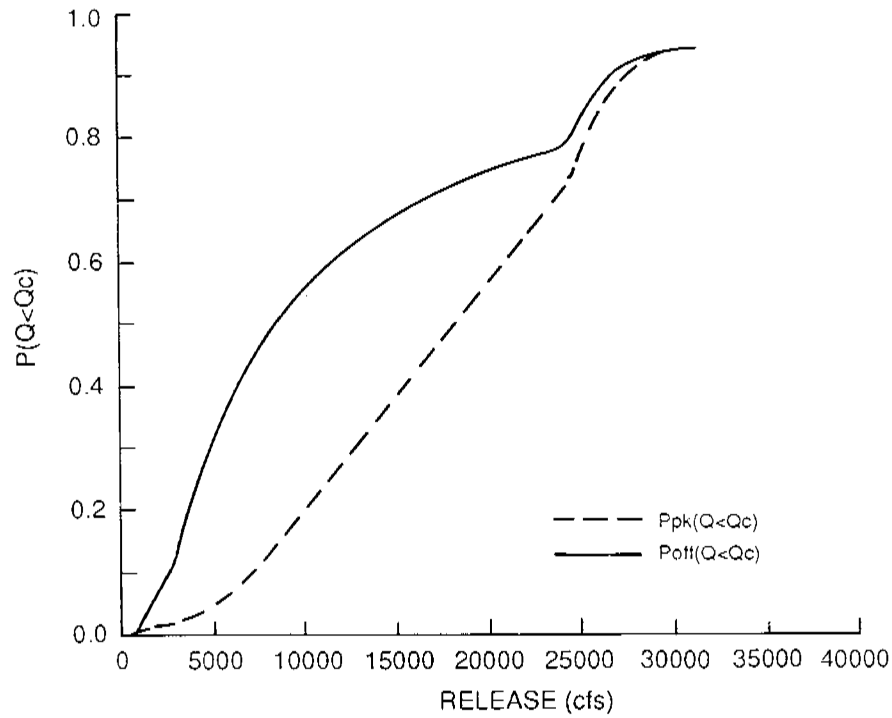


FIGURE 9-3 Glen Canyon Dam release probabilities during peak and off-peak hours (1978-1989).

value (nights) and 5 and 12% during peak valued hours. The functions also show that flows were above the 31,000-33,000- cfs capacity of the turbines 5% of the time (during the flood of 1983 and 1984).

WAPA MODELS OF INCREASED MINIMUM FLOWS

GCES I Model

In response to the NRC review of a draft of the GCES I report, WAPA was requested to develop (rather quickly) an analysis of the probable economic impacts of increasing minimum releases from GCD from 1,000 or 3,000 to 5,000 and 8,000 cfs all year. They produced a report (WAPA, 1988) which estimated $5.0 million and $14.7 million of increased annual cost to energy users during the next decade and much larger increases after 1999.

WAPA's approach to this calculation was to define a base case representing historic dam releases during the entire period of record (1965-1987) as a reference from which to estimate increases in off-peak and decreases in on-peak water releases and then to translate these water release changes into changes in generating capacity (megawatts) and energy (megawatt-hours). The data from which the base case was developed were monthly releases for the 23 years of operation of GCD, from which time-of-week excedance functions were developed. From these excedance functions, the flows related to probability levels upon which firm capacity (capacity available 90% of the time) and energy marketing (average historic megawatt hours) are based were determined. The complex analyses of changes in firm and nonfirm sales, fuel replacement sales, and wheeling of energy from other sources were all then calculated as functions of incremental changes from this base case.

The time-of-week excedance function used for the base case was derived not from hourly data (even though they were available) but by assuming constant flows equal to minimums allowed (1,000 cfs in winter and 3,000 cfs in summer) 100% of the time during off-peak hours. The peak-hour releases were then calculated by allocating the remaining volume of water in the monthly data base to these hours. Peak hours on weekends were assumed to be at about 48% of the weekday peaks.

The difference between the WAPA results and the actual average monthly peak and off-peak releases are displayed for 1982 (a slightly above average inflow year) in Figure 9-4. The assumption that actual off-peak flows equal minimum flows is extremely bad. It introduced an error of as much as 700% in winter (always too low) and was never closer than 33% to the measured data during summer. The annual average during off-peak hours is closer to 6,000 than to 1,000 or 3,000 cfs. This initial assumption caused a consistent overestimation of peak flows for the base case (also shown in Figure 9-4). The analysis then proceeded by changing the bottom line in the figure to a constant 5,000 or 8,000 and lowering the peak period flows as required to maintain the same monthly mass balance. It is very difficult to place any credence in the accuracy of the 1988 WAPA economic impacts, given the large errors in the basic assumption which drives all subsequent calculations in the report.

Although only a single year is shown in Figure 9-4, the conclusion would be the same for any year in the 23 year data base used by WAPA: off-peak flows are at the minimum allowed during only a small fraction of the time, and therefore the analysis must be based on expected values determined from hourly data, not from an assumption of constant flow at minimum level.

A logical question arises from the results shown in Figure 9-4: Since it is in WAPA's interest to operate GCD at the minimum possible release level during off-peak hours, why was this such a bad assumption (why don't they operate that way)? The answer is evident from observing the truly

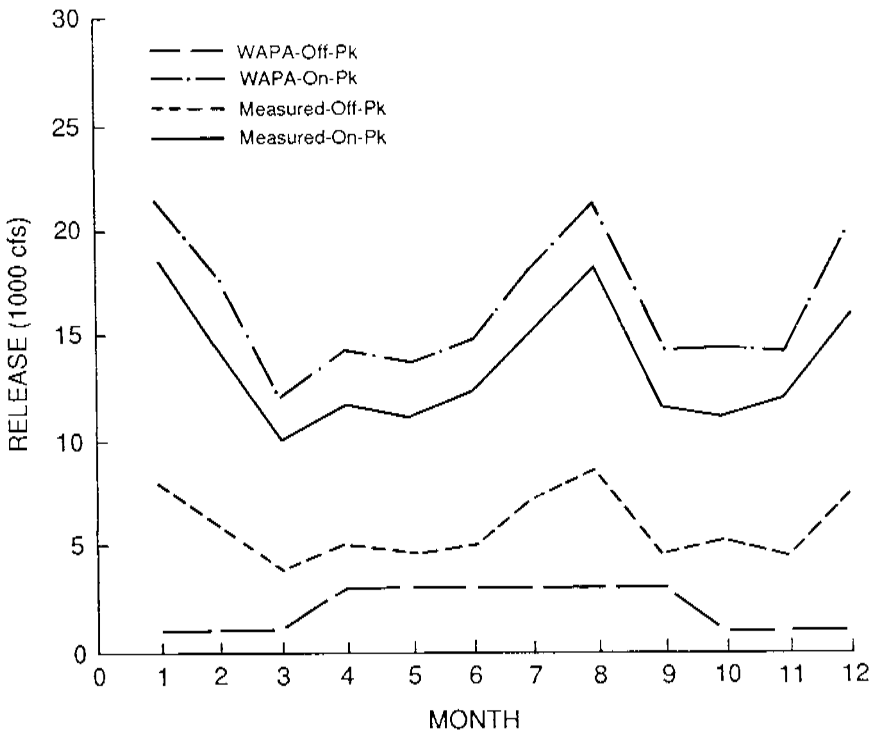


FIGURE 9-4 Comparison of WAPA 1988 model and actual measured data (on-peak and off-peak, 1982).
SOURCE: WAPA, 1988.

random energy load that the dam operators are attempting to follow. An example of hourly actual generation (July 1982) is shown in Figure 9-5. Although the scale is in megawatts, it can easily and with reasonable accuracy be interpreted as flow in cubic feet per second (given the knowledge of an essentially full reservoir for calculating head) by using a conversion of 1 mw = 25 cfs. The minimum July release of 3,000 cfs (120 MW) is seen to occur on several days, but only for 1 or 2 hours at a time. Another way of reaching this obvious conclusion is that if a random variable has a high variance and has a lower bound of 3,000 cfs, its expected value is always going to be much higher than 3,000.

One should note that even though average releases in off-peak periods were greater than 5,000 cfs during the example year discussed above, it should not be concluded that raising the allowable minimum to 5,000 will have no effect. From reasons discussed above, an operator following a new random load and a higher minimum release will produce an average release

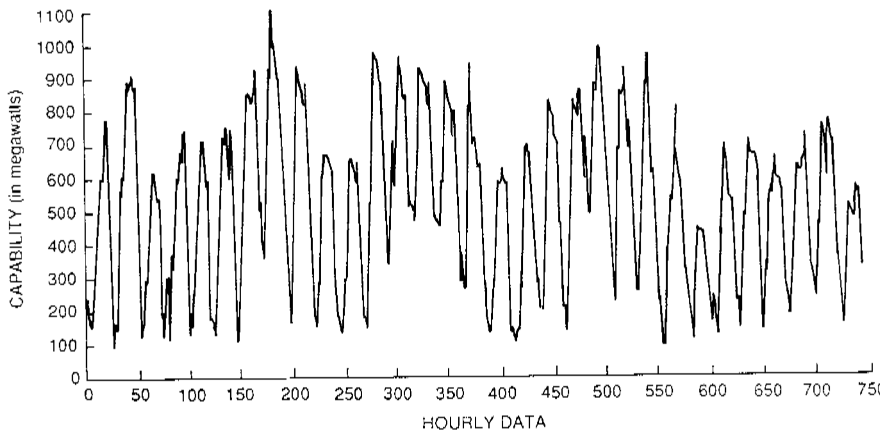


FIGURE 9-5 Actual generation for July 1982.
SOURCE: WAPA, 1982.

higher than before, and therefore the change will have an economic effect. How much higher than the previous off-peak original average is the difficult question upon which the GCES II operations study should be focused.

The answer to this question was obvious for the assumption used by WAPA—if the base case flow is always at the minimum, then the alternative minimums also should equal the flow during off-peak hours. With the much more accurate assumption, however (the expected value of average flows during off-peak periods), the increment of increase is not obvious. The effect in the short run may be minor because there will be no change in the firm power contracts (only in the other types of purchases and sales) and therefore no change in the load. In the long run (new contracts), increased minimum flows will likely motivate an increase in the firm contract requirement of off-peak minimum capacity and energy equal to 35% of peak period. Although the current 35% requirement is much greater than the minimum related flows, it is not necessarily greater than the average resulting from higher minimums, and periods when load is less than minimum generation could result if this contract requirement is not increased.

OTHER RELATED WAPA REPORTS

Report on Impact of Alternative Interim Flows

WAPA has also produced a report related to the impact of possible increased minimum flows during the next 5 years (WAPA, 1989). This report presented results in a much different framework than the 1984 report, focusing on decrease in flexibility of marketing due to these possible alternative flows. Details of the method used related to the model logic for the base case were not included. It will therefore not be reviewed here; however, there is no indication that anything other than monthly data were used for the analysis.

Report on Cost of Research Flows

WAPA has produced a report on the economic impact of experimental flows planned by the GCES II program during 1990 and 1991 (WAPA, 1990). The estimated cost was $10.9 million. The report is documented very well (thank you), which allows an analysis of the model logic similar to that of the 1988 report. The all important base case was developed as follows: the CRSP load during 1990-1991 was assumed to be the actual load (78% of which was at GCD) for 1989, and the monthly averages for peak and off-peak periods were calculated by using hourly data. The load, however, is not the same as the generation pattern at GCD because of fossil fuel purchases and other transactions. The base case generation pattern at GCD was therefore estimated in a manner similar to that used for the 1988 report except that the assumed minimum releases were increased to 1,000 cfs above the minimum flows of 1,000 and 3,000 cfs. This results in off-peak volumes of 2,825 acre-feet (8 hours/day) in summer and 1,325 acre-feet during off-peak hours in winter. This increase recognizes that a random variable cannot have a mean equal to its minimum. Again, however, this step in the right direction appears to be too small. Figure 9-6 compares the actual measured values for 1989 peak and off-peak generation from GCD to those used for the WAPA base case. The summer off-peak model (months 4 through 9) is reasonably accurate except for one month, but again, the winter model is in error by more than 100%. The underestimation of off-peak releases results in an overestimation of base-case peak period releases, as shown by the difference between the two upper lines. This resulted in a corresponding overestimation of the impact of the experimental flows.

GCES ECONOMIC TEAM PROGRESS TO DATE

The GCES II economic study team has completed an initial report (Bureau of Reclamation, 1990) on one important aspect of the way in which the impact of increased minimum flows should be analyzed—that is, what type of model is best for predicting the nature of the response to increased minimum flows by large utilities that are firm power customers of CRSP. The implication of this question is that if the ability of GCD to provide peaking energy is reduced, an increment of capital investment (and related

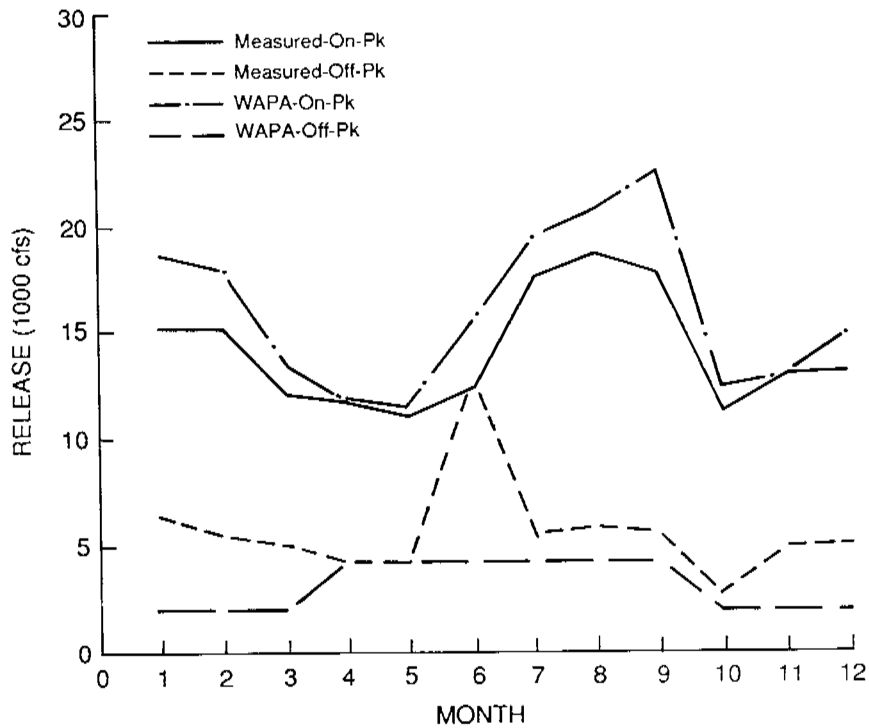


FIGURE 9-6 Comparison of WAPA model and actual measured data (on-peak and off-peak, 1989).
SOURCE: WAPA, 1989.

increased operating cost) in some type of alternate source will, at some future time, be required. The approach used in this report (Bureau of Reclamation, 1990) to solve this investment timing problem was to develop a hypothetical system including three firm power customers that each have other sources of energy. This system was then modeled by three different approaches: (1) ELFIN-an energy system simulation model developed by the Environmental Defense fund; (2) EGEAS-an investment timing optimization model used by the Electrical Power Research Institute; and (3) ATPM (alternate thermal power method), which is a much simpler approach sometimes used by WAPA to the estimate cost of an alternate source.

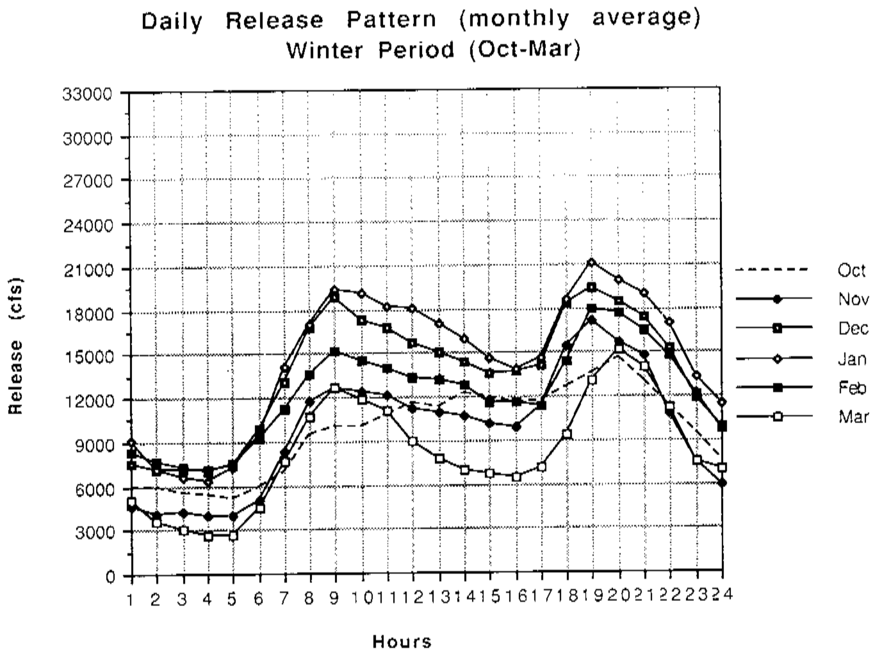
The report's conclusion is that both ELFIN and EGEAS should be used in the GCES study and their results should be compared. It should be noted that the focus of the report is on the investment timing and estimation of which type of alternative energy source is likely to result from changes at GCD. The economics/operation study team has not yet addressed the more basic problem (how much impact in peaking capability will result) that was addressed in the WAPA reports discussed above. It is likely that any reasonable approach to the investment timing problem and the selection of which type of generating source is likely to be added will be adequate, because this information is much less important to the total question of evaluating impacts than are the basic assumptions that drive the calculation of the megawatts and megawatt-hours of reduction in peaking capability at GCD. Consider that while GCD is 78% of the CRSP capacity, CRSP is only 13% of the WAPA system capacity, and WAPA represents about 1.3% of the entire western U.S. generating capacity. A loss, for example, of 20% in GCD peaking capacity would be a 0.25% loss to the system from which ELFIN and EGEAS are attempting to model impacts. The probability of accurately predicting the future impact of such a marginal change in this very large system seems very low.

Ramping Rates

One parameter that is related to environmental objectives but was not modeled in previous WAPA reports is the rate of change of releases from GCD—the ramping rates. The research releases requested by GCES, however, specifically require both high and low ramping rates. It was necessary for WAPA to define the terms *high* and *low* before the cost of these flows could be modeled in the 1990 report on cost of research flows. The terms were therefore interpreted as high = 7,200 cfs/hour and low = 3,600 cfs/hour. The ramping rate, either up or down, can be viewed as the derivative of the release hydrograph. In the WAPA report, the shape of the daily-release hydrograph is determined by assuming that ramping up begins at 8 a.m. (the first hour of the peak period) and ramping down ends at midnight (the beginning of the off-peak period). This means that the entire off-peak period is modeled at the lowest rate and all ramping occurs during the peak hours.

The typical historic pattern is difficult to summarize. The average hourly release rates for each month for 1982 are shown in Figure 9-7. Note that the winter months have two distinct peaks (one at 9 a.m. and another at 7 p.m.) The ramping up begins at 5 or 6 a.m., and it would therefore appear to be more accurate to model the beginning and end of ramping during off-peak hours, perhaps splitting the ramping period between the two periods about equally. The summer months have a single daily peak (except for April, which has the winter-month shape), with ramping beginning at 6 a.m. and peaking at 2 p.m.

Care should be taken in making conclusions about ramping rates from Figure 9-7; however, the points each represent averages of about 30 values each hour, which eliminates much of the randomness. To get a better



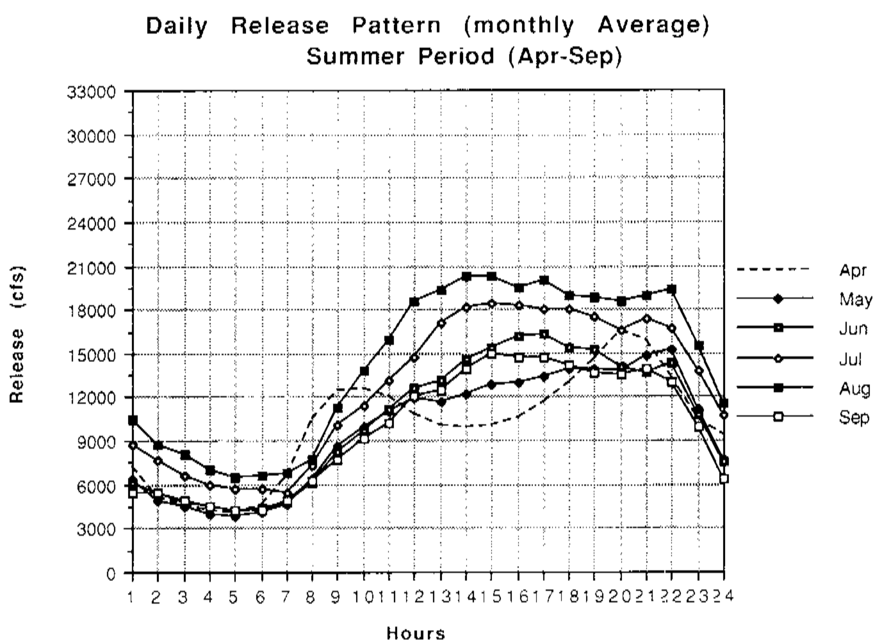


FIGURE 9-7 Hourly average releases each month during 1982.
SOURCE: WAPA, 1982.

perspective of real-time operation, consider Figure 9-8, which shows actual operation for a single weekday (July 29) during a high-demand month of 1982. Figure 9-8 shows actual dam releases, the average releases for peak and off-peak hours, and an assumed load. The hypothetical load must always be greater than the 35% of firm capacity (about 10,700 cfs), and the integral of the area between the dam release line and load represents kilowatt-hours of fossil fuel purchased during off-peak hours. The firm sales line during peak hours is also drawn arbitrarily. The integral of the area between the dam release line and the firm sales line represents sales on the spot market. This quantity may actually have been zero on this day, indicating that all sales were to firm customers. The water saved at night by buying fossil fuel may be sold to nonfirm or either firm customers or both, and it may be sold on the same day or on any other day. Note that the USBR monthly target imposed on WAPA for July 1982 was apparently 0.66 maf. This can be determined by multiplying the average monthly releases during off-peak hours (7,300 cfs) and peak hours (15,000 cfs) by the frac-

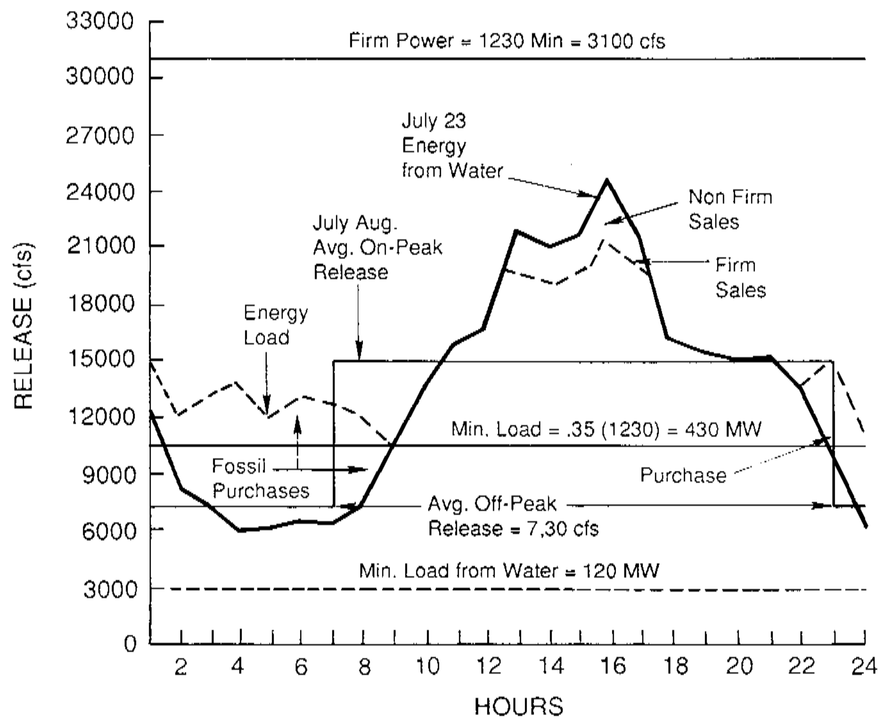


FIGURE 9-8 Daily power releases.
SOURCE: WAPA, 1982.

tion of monthly hours for these two periods (0.52 and 0.48) and multiplying the sum by the number of acre-feet in a cfs month (about 60). The fraction of peak and off-peak hours assumes that weekend and holiday days are all off-peak.

The results of the research flows cost model should be interpreted in relation to differences between the experimental and historic ramping rates. This raises the question, What are the historic ramping rates? The hourly data for all 23 years of operation of GCD were used to develop the following summary of historic ramping rates. The average maximum ramping rates in delta cfs/hour for durations of 1-7 hours are shown in Figure 9-9 for each of the 7 days of the week. Since the data base used contains 24 years of 52 weeks each, there are 1,248 measurements (one for each day of the week) for each quantity shown. The average maximum is therefore obtained by calculating the maximum change in flow rate over the selected duration for 1,248 days and finding the mean. The standard deviations of these

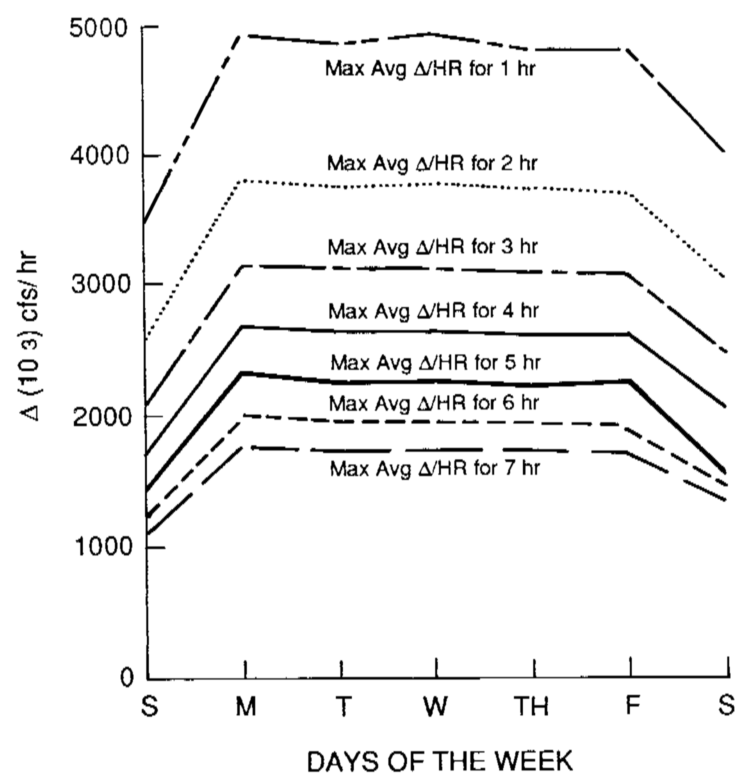


FIGURE 9-9 Summary of historic ramping rates.
SOURCE: Upper Colorado River Commission, 1987.

statistics vary from 2,015 to 2,723 cfs for the 1-hour duration and from 590 to 836 cfs for the 7-hour duration.

The ramping rates selected for research flows were either 3,600 or 7,200 cfs/hour. The 7,200 rate is about 1 standard deviation above the maximum average of the historic record for 1-hour duration, and therefore rates higher than 7,200 have been experienced during about one-sixth of the days of record. The low rate of 3,600 approximates the daily average maximum for 2 hours and is about double the average maximum for 7 hours.

Flows in the Grand Canyon Relative to Dam Releases

A distinction should be made between dam releases and flows through the Grand Canyon. The downstream peaks will be lower and the minimums will be higher than the rates of release from the dam. The USBR has developed a routing model which attempts to predict this relationship at 5 downstream locations: Lee's Ferry, Little Colorado, Grand Canyon gage, National Canyon, and Diamond Creek. The model results estimate that typical peak flows in the Grand Canyon sites are about three-fourths of the peak rates leaving the dam (nine-tenths at Lee's Ferry) and the minimum flows are about double those leaving the dam. The lag times between the dam and these locations are of course a function of flow rate (with high flows overtaking low flows), but a decreasing sequence of relatively low flows is estimated to have the following lag times in hours: 3 to Lee's Ferry, 19 to Little Colorado, 29 to Grand Canyon, 44 to National Canyon, and 56 to Diamond Creek. These times seem to differ substantially from those reported in the GCES newsletter as being measured during a dye study in October 1989. During the research flows of 1990-1991, continuous measurements of flow rates at all of these gages should be made to enable testing and improved calibration of the USBR routing model.

Conclusions

1. The GCES II economic impact research team, which is charged with analyzing the economic cost of possible increased minimum releases from Glen Canyon Dam, should use hourly historic data for developing both the generation and load probability distributions. This apporach will improve the modeled shapes of both the load pattern and the dam release pattern relative to those used in the WAPA reports to date.

2. The shape of the typical daily release pattern used to represent both the base case and the modified operating policy should include explicitly the ramping between peak and off-peak hours. This will allow analysis of the cost of reduced allowable ramping rates as well as increased minimum

flow rates. The economic impact of ramping rate limits could conceivably be as important as that of minimum flow increases.

3. The role of WAPA's marketing policy of 35% minimum fraction of firm load during off-peak hours, and possible future variations of that requirement (either up or down), should be included in the economic analysis.

4. The question of how much (if any) an increased minimum dam release requirement will change the CRSP firm energy load, in both the near and long terms, should be included in the analysis by the economic research team.

5. Neither the current operating mode of GCD with its large diurnal fluctuations, nor any reasonable modification to the current minimum release criteria will have any impact upon the ability to meet the law of the river.

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