

A CONTROL MODEL FOR HYDROPOWER SYSTEM ANALYSIS AND OPERATION

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INTRODUCTION

In North America, hydropower provides a significant portion of the electrical capacity, ranging from about 60 percent in Canada, to more than 30 percent in Mexico, to about 13 percent in the U.S. (North America Hydroelectric Research and Development Forum, 1992). Among the attractive features of hydropower is that it is renewable, clean, efficient, economical, and domestically produced. In the U.S., the amount of hydroelectric production is equivalent to nearly 500 million barrels of oil annually, which, at today's oil prices, have a value of \$9 billion. In addition to meeting electricity demands, hydropower facilities play a critical role in water management, helping to provide flood control and water for irrigation, municipal and industrial uses, navigation, recreation, and fish and wildlife preservation.

Improving the way projects are operated is a top research need. It is worth noting that a 1 percent increase in the efficiency of existing hydro plants in the U.S. would provide an additional 3 billion kilowatt-hours of electricity annually, saving the equivalent of 1.4 million tons of coal or 4.9 million barrels of oil (North American Hydroelectric Research and Development Forum, 1992).

The primary motivations for this research work are (1) to demonstrate that modern optimization methods can effectively optimize the utilization of hydropower facilities and (2) compare the relative performance of optimization and the more traditional simulation models. In this article, we take up the first task and describe the problems addressed, the models developed, and the results obtained. The second task will be the subject of a panel discussion.

CASE STUDY SYSTEM AND DATA

The case study system (Figure 1) encompasses the Chattahoochee River Basin above Atlanta to below Peachtree Creek, including Lake Lanier, and the Coosa River Basin above Rome, Georgia, including Lakes Allatoona and Carters.

Table 1: Active Storage and Elevation Ranges

Lake	Minimum Storage (acre-ft) /Elevation (ft)	Maximum Storage (acre-ft)/Elevation (ft)
Lake Lanier	867600/1022	1917000/1071
Lake Carter	242200/1035	377100/1070
Lake Allatoona	82890/800	367470/840

Table 2: Turbine Operational Ranges

Lake	Minimum (MW)	Maximum (MW)
Lanier		
Large Turbines (2)	10.0	46
Small Turbine (1)	2.2	6.9
Allatoona		
Large Turbines (2)	5.0	41.4
Small Turbine (1)	0.35	2.3
Carters		
Conventional Turbines (2)	50.0	143.75
Pump-Turbines (2)	50.0	143.75

The main data sources for this system are the reservoir regulation manuals prepared by the U.S. Army Corps of Engineers, Mobile District. Additional data were obtained by the Atlanta Regional Commission, the Southeastern Power Administration, and Georgia Power Company. A detailed compilation and analysis of the data used in this study appears in Georgakakos et al., 1995, Appendix A. In particular, the active storage ranges for the three reservoirs were assumed as shown in Table 1.

With regard to turbine power capacity, a 15% overload was assumed possible, resulting in the following operational ranges

shown in Table 2.

The present water demand requirements of this system are depicted on Figure 2. More specifically, the demand conditions for the Chattahoochee River Basin are as follows:

- The withdrawal of Gwinnett county amounts to 54 mgd (million gallons per day) as an annual average from Lake Lanier. Of this, 8 mgd are returned above Peachtree Creek at the "Combined Return" control point shown in the figure.
- Fulton/Dekalb withdrawal: 107 mgd annual average from Chattahoochee River above the Morgans Falls site; 16 mgd are returned at the combined return control point.
- Cobb Co. Marietta Water Authority/Atlanta withdrawal: 165 mgd annual average from Chattahoochee River below the Morgans Falls site; a portion of this withdrawal is returned to the river below Peachtree Creek. Since the minimum flow requirement concerns the control point above Peachtree Creek, this return flow will not be modeled.

The future demand conditions in the same basin are projected as shown below (Figure 3):

- The withdrawal of the Gwinnett county amounts to 105 mgd (million gallons per day) as an annual average from Lake Lanier. Of this, 19 mgd are returned above Peachtree Creek at the combined return point. Alternatively, the 19 mgd may be returned to Lake Lanier.
- Fulton/Dekalb withdrawal: 159 mgd annual average from

Chattahoochee River above the Morgans Falls site; 39 mgd are returned at the combined return point.

- CCMWA/Atlanta withdrawal: 220 mgd annual average from Chattahoochee River below the Morgans Falls site; a portion of this withdrawal is returned to the river below Peachtree Creek.

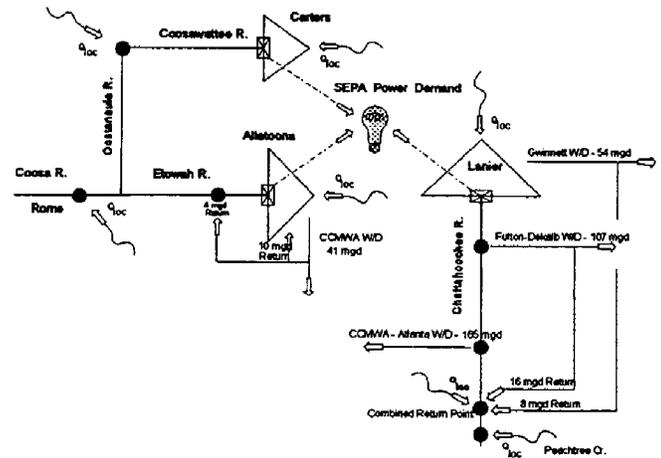


Figure 2: Case study system conceptualization - present water demand conditions.

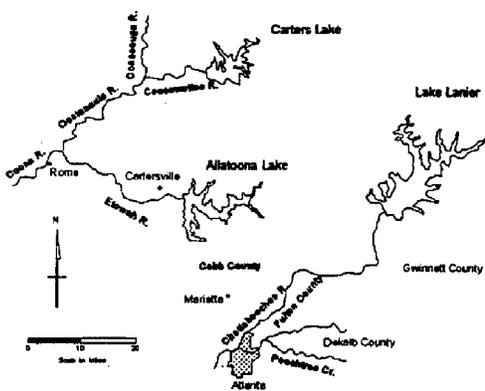


Figure 1: Case study reservoir system.

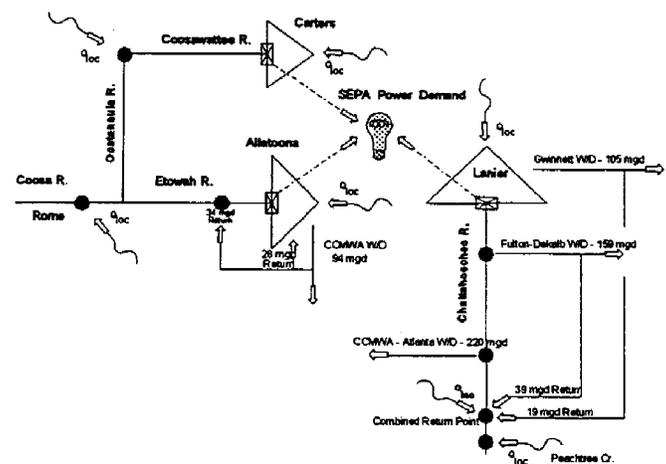


Figure 3: Case study system conceptualization -future water demand conditions.

The corresponding requirements at the Coosa River Basin are as follows:

- Baseline (present) condition (Figure 2): The CCMWA/ Cartersville withdrawal amounts to 41 mgd from Allatoona, of which 10 mgd return to Lake Allatoona and 4mgd return to the Etowah River below the lake.
- Future condition (Figure 3): The CCMWA/ Cartersville withdrawal amounts to 94 mgd annual average from Allatoona, of which 28 mgd return to Lake Allatoona and 34 mgd return to the Etowah River below the lake.

To maintain instream water quality, the minimum flow requirement below Peachtree Creek is 750 cfs daily average for both present and future demand scenarios. The inflow data used in this study include the hydrologic periods from July 5, 1987, to December 31, 1988. This hydrologic period was taken as a representative of a drought sequence and was used in the study of the system dependable capacity and firm energy.

CONTROL MODEL OVERVIEW

The optimization (control) model developed for this system is designed to address several aspects of hydropower system analysis and operation and includes two basic modules (Figure 4): A turbine load allocation and a reservoir control module. The turbine load allocation module aims at optimizing hydroplant efficiency by allocating the power load among the individual turbines such that the total plant outflow is minimized. The inputs to this module include beginning-of-the-period storage levels, turbine and reservoir characteristics (e.g. elevation vs. storage and tailwater vs. discharge relationships, power vs. net hydraulic head vs. discharge curves, and operational turbine ranges, among others), and minimum and maximum discharge requirements. This module utilizes Dynamic Programming (Bellman and Dreyfus, 1962) as the optimization procedure and is "run" first for each hydroplant to derive the optimal relationship among total system outflow, total plant load, and reservoir elevation. This relationship is expressed in analytical form via regression analysis and is the connecting link between the two optimization modules. Namely, for any combination of total plant load and reservoir elevation, this function gives the lowest attainable discharge and specifies the turbine loads that make it possible.

The second control module optimizes the system performance over time. This module aims at controlling the reservoir system so as to maximize the dependable power capacity, the energy generation, or the value of energy generation. Its inputs include reservoir inflows, physical reservoir layout and characteristics (e.g., storage vs. elevation curves, storage and release constraints, etc.), the relationships between minimum discharge, reservoir elevation, and plant load, determined by the first module, weekday and weekend release and power generation requirements, and costs for thermal plant fuel usage. The

optimization philosophy of this module is based on the Extended Linear Quadratic Gaussian (ELQG) control method (Georgakakos and Marks, 1987, Georgakakos, 1984, 1989, 1991, 1993), but includes several original extensions. This module generates optimal power load sequences for each hydroplant which maximize the stated objective while meeting all applicable constraints.

The previous description strictly applies to the control model used for determining the system dependable power capacity and maximizing the value of hydro-energy. In the optimization of energy generation, the two-module framework is the same, but the first module is designed to derive a relationship between total daily outflow versus energy generation and reservoir elevation. For a full description of the various model components, the reader is referred to Georgakakos et al., 1995. In what follows, we present results from the use of this model in dependable capacity optimization.

DEPENDABLE CAPACITY (DC) OPTIMIZATION

Dependable power capacity of a system of hydropower facilities is the load-carrying ability of the system under adverse conditions (Corps of Engineers Hydropower Manual, 1985). The value of the dependable power capacity is the cost of the private sector to construct thermal power facilities to replace the dependable capacity of the hydrosystem. DC is usually determined as the capacity available during the period of maximum drawdown (POMD). POMD is the period of adverse hydrologic and demand circumstances for which system

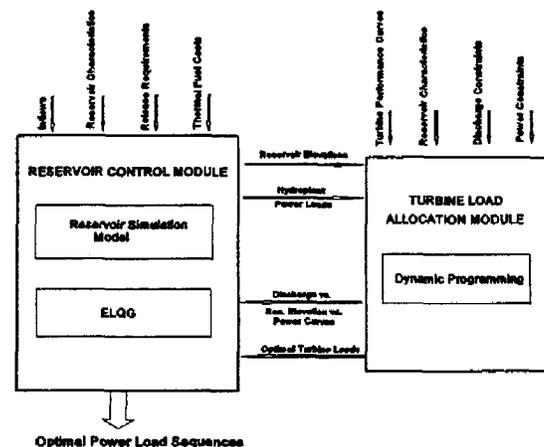


Figure 4: Control model overview

operation ensures dependable yields for hydropower and all other system objectives. It is the time period during which the system proceeds from full storage to minimum storage and then refills. In practice, dependable capacity determination is performed using water-budget simulation models which do not leverage differences in power generation efficiency among projects and do not optimize system response across basins. The control model developed in this work accounts explicitly for these elements and provides a more accurate estimate of the dependable capacity of a hydropower system.

The dependable power capacity of the Lanier-Allatoona-Carters system was determined for $\Delta t=2, 3, 4, 5,$ and 6 hours. Δt is the time period within each week-day during which hydropower generation is equal to the dependable capacity. The optimal value of the dependable capacity in each case is reported in table 3.

In the $\Delta t=4$ hour case, dependable capacity was also optimized under future demand conditions. The optimal value was 241 MW as compared to 246 MW for the present conditions case. As a general remark, the projected water demand increases are small relative to the inflows and the available storage, and do not make an appreciable difference in the value of the dependable capacity.

Table 3: Dependable Capacity Optimization: Present Water Demand Conditions

Δt (hours)	2	3	4	5	6
Dep. Cap (MW)	340	294	246	210	180

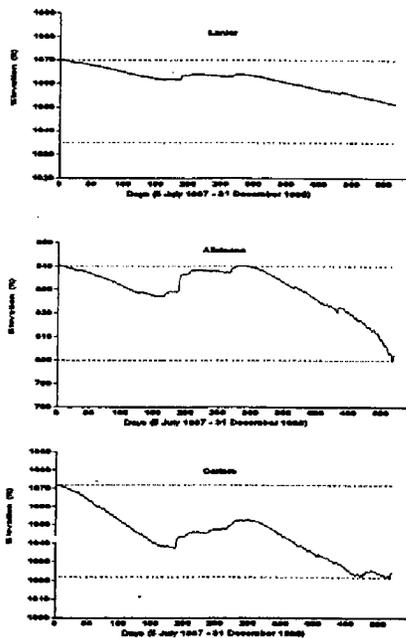


Figure 5: Elevation sequences; dependable capacity optimization; $\Delta t=4$ hours.

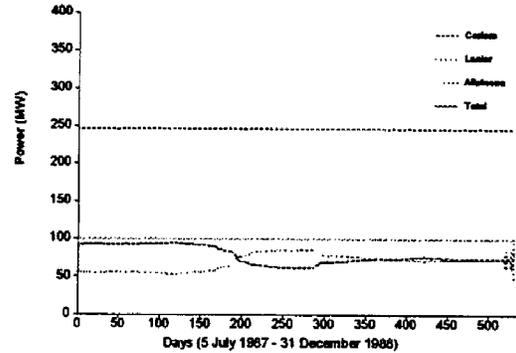


Figure 6: Power sequences; Dependable capacity optimization; $\Delta t=4$ Hours.

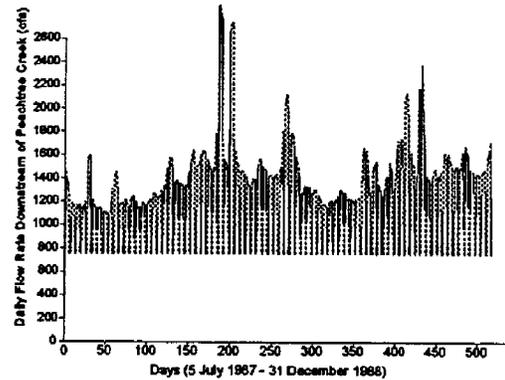


Figure 7: Flow sequence downstream of peachtree creek; dependable capacity optimization; $\Delta t=4$ hours.

Figures 5, 6, and 7 include more detailed information on the $\Delta t=4$ run. More specifically, Figure 5 shows that Carters and Allatoona are fully depleted, while Lanier has still plenty of storage and generates at full power capacity. An important feature of the power sequences (Figure 6) is the power

compensation between Carters and Allatoona. As the efficiency loss of Allatoona's power plant with elevation is much more pronounced than that of Carters', Allatoona starts off at low power to minimize its drawdown during the initial dry period. During this time, Carters picks up the power deficit and consequently uses more than half of its storage. When Allatoona's elevation nears full storage, it begins to generate at full power, allowing Carters to reduce its generation and build up storage. Toward the end of the time horizon, both plants generate to sustain the dependable power capacity of $P=246$ MW while prolonging their full depletion as much as possible. Figure 7 shows that the release sequences always satisfy the minimum flow requirement at Peachtree Creek.

By comparison, the dependable capacities determined using the HEC-5 simulation model for the same system and under the same operational constraints and assumptions are consistently lower by about 10 to 20 percent in all cases (G. McMahon, personal communication, 1995). Thus, the traditional approach of "constant power at every reservoir" is only optimal in the trivial case where there exists enough storage to generate at full power. In the more typical case, reservoir storage falls short of this commitment, and dependable capacity optimization requires the coordination of all system power plants. This is a non-trivial optimization problem which becomes increasingly difficult as differences in plant generation efficiencies, inflow characteristics, and storage capacities become larger. Thus, in such cases, optimization models gain a serious advantage over traditional simulation-based analyses.

CONCLUSIONS

In this article, we presented a summary of our recently completed research on hydropower system modeling and optimization. While, our focus here was the optimization of dependable capacity, our research includes several other new formulations and models. These relate to

- the determination of the dependable power capacity for a system of hydropower facilities,
- the determination of the firm energy for a system of hydropower facilities with or without dependable capacity commitments, and
- the optimal use of hydropower facilities for minimizing thermal fuel consumption.

Overall, these models were shown to be efficient and reliable, and able to incorporate all important system idiosyncrasies and operational constraints. These experiments made clear that as the system complexity increases, so does the benefit from using formal optimization procedures. By contrast, simulation-based analyses of hydropower aspects produce results that are consistently suboptimal by a significant margin. Based on our

experience with the case study system, this disparity between optimization and simulation approaches is expected to increase as the system becomes large and more complex. One implication of this is that the hydropower analyses conducted for the comprehensive study using a simulation model can at best be viewed as only approximate. *A more detailed optimization analysis is needed to quantify the true capacity of the ACF-ACT system to meet hydropower objectives.*

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