Optimal Economic Dispatch of Hydroelectric Projects on the Roanoke River

By Brian J. McCrodden, P.E., HydroLogics, Inc.,
Dean Randall, Ph. D., P.E., HydroLogics, Inc., and
James W. Thornton, Dominion Virginia Power

ABSTRACT

Dominion Virginia Power/North Carolina Power (Dominion) owns and operates the Gaston and Roanoke Rapids hydroelectric project (two hydroelectric dams) on the Roanoke River in central Virginia/North Carolina. The project is immediately downstream of the federally-owned John H. Kerr Reservoir, which is operated by the U.S. Army Corps of Engineers. Energy from Kerr Reservoir is earmarked for customers of the federal Southeastern Power Administration (SEPA). By agreement, however, since early 2005 when it entered the PJM regional transmission organization, Dominion has scheduled the generation from all three dams. (PJM Interconnection is the regional transmission organization for the mid-Atlantic region.) In return, Dominion guarantees delivery of SEPA's scheduled energy, either from Kerr Reservoir or from other system resources.

Dominion's project was relicensed by the Federal Energy Regulatory Commission (FERC) in 2004. The new license contains numerous operating constraints that are manifest in terms of lake levels and downstream releases.

The near-simultaneous occurrence of these three events (imposition of the new license conditions, entry into the PJM market, and takeover of the dispatch scheduling of Kerr Reservoir) caused significant changes in the operation of the system, which made it difficult to comply with the new license. This led to "on-the-fly" modifications to the schedule that were inefficient, expensive, and caused considerable stress among operating personnel. In addition, because the license now includes a number of adaptive provisions, the operational scheme may change every five years.

Dominion sought a more rigorous and robust means of scheduling its hydropower portfolio and turned to HydroLogics, Inc., in part because HydroLogics had developed the simulation model used in the relicensing process.

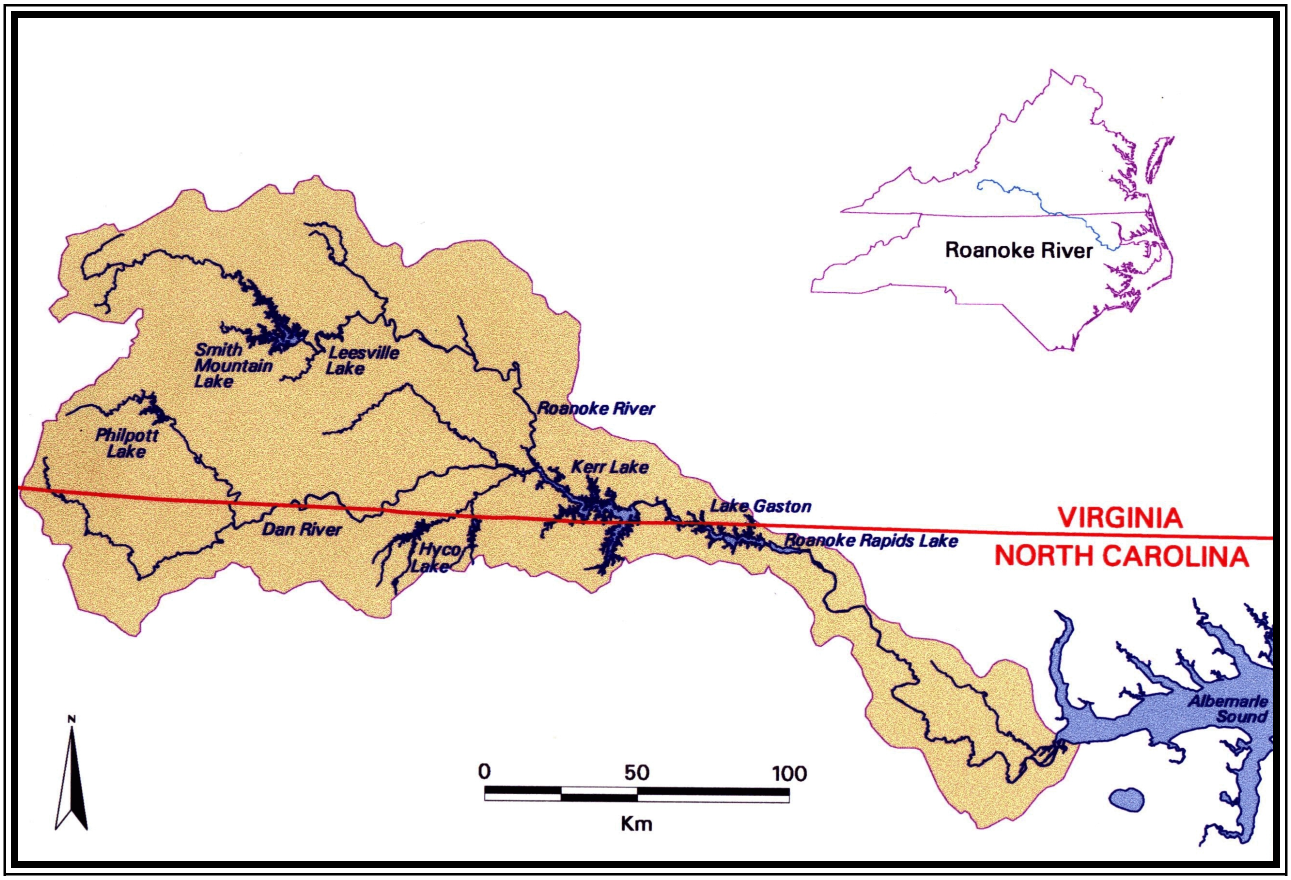
Dominion's objective in this new operating environment is to maximize the net revenue that can be generated from the three-reservoir system without violating any of its license constraints. The selected approach uses both simulation and optimization applications of HydroLogics' OASIS software. The technique involves simulating today's generation (which was scheduled yesterday) to get up-to-date starting conditions as of midnight tonight. An hourly optimization model is then used to schedule tomorrow's generation based upon the energy target and the prices forecast for the remainder of the week. The process is repeated daily or more often if conditions change markedly during the day.

Presented at The Waterpower XV Conference, July 23-26, 2007.

Introduction

Dominion owns and operates two hydroelectric dams on the Roanoke River that are licensed by FERC as one project. Lake Gaston straddles the Virginia-North Carolina border, immediately downstream of the federally-owned John H. Kerr Reservoir, which is operated by the U.S. Army Corps of Engineers. Roanoke Rapids Lake is just downstream of Lake Gaston and is the control point for downstream releases. A diagram of the system in the larger context of the Roanoke River is shown in Figure 1.

Figure 1. Roanoke River Basin



Smith Mountain and Leesville Lakes are a pump/storage pair owned by Appalachian Power Company. Philpott Lake is another federal project. It and Kerr Reservoir comprise SEPA's Kerr-Philpott system, but the operation of Philpott has no direct impact on the scheduling of energy from Dominion's project.

Kerr Reservoir was constructed in the late 1940s, principally as a response to the 1940 flood-of-record , which had an estimated peak discharge of approximately 260,000 cfs. The authorized purposes of the project are flood control, hydropower, recreation, water supply, fish and wildlife, and low flow augmentation. The Corps of Engineers has primary flood control responsibility for the basin, and during flood events it coordinates the use of Dominion's as well as Appalachian Power Company's storage and directs downstream releases from Roanoke Rapids. Pertinent data concerning the three projects are shown in Table 1.

Table 1. Project Data

	John H. Kerr	Gaston	Roanoke Rapids
Drainage Area (sq. mi.)	7,780	559	32
Usable Storage (ac-ft) (excluding flood control)	1,027,000	20,000	20,000
Capacity (MW)	225	220	100
Maximum Discharge (cfs)	33,000	44,000	18,500

In 2003 Dominion reached agreement with a number of stakeholders concerning the issuance of a new FERC license for the Gaston and Roanoke Rapids project. The new license was issued in 2004. Not unexpectedly, it contains a number of new and more stringent operating conditions. In terms of its impact on the economic dispatch of the system, the most important are tighter constraints on lake levels, more sophisticated downstream release protocols, and the instantaneous and daily average dissolved oxygen limits associated with those releases. Note from Table 1 that the usable storage in Lake Gaston represents slightly over seven hours of run time from Kerr when Kerr is running at full plant. There is also a substantial wave associated with a release from Kerr unless there is a concurrent release from Gaston. This means that an action at Kerr that is not followed fairly promptly by a reaction at Gaston (and Roanoke Rapids) can quickly lead to a license violation. (Fortunately, the four-hour travel time between Kerr and Gaston provides some additional flexibility.)

Energy and capacity from the Kerr project are marketed to preference customers by SEPA and delivered via contract through publicly-owned utilities, including Dominion. Prior to 2004, Dominion scheduled the energy that it delivered from Kerr and was thus able to control its lake levels, even if it meant providing the energy for SEPA's customers from other parts of its generating system.

In anticipation of deregulation (as required by Virginia law) and because some of SEPA's customers had expressed an interest in self-scheduling, in 2003 Dominion and SEPA negotiated an agreement whereby SEPA would assume dispatch responsibilities at Kerr on January 1, 2004.

This proved problematic for Dominion. Because of its limited storage and because it now had no control over the releases from Kerr, Dominion's operations were necessarily constrained to "follow" Kerr – peaking where possible within the limits of its FERC license. Operating personnel, who were responsible for license compliance, were quite conservative and tended to leave plenty of buffer between the license limits and the actual releases and lake levels. Even so, they had considerable difficulty controlling lake levels, particularly when the new license became effective in March. In addition, the mismatch in hydraulic capacities coupled with the times of travel between the three powerhouses meant that the economic benefit derived from this method of operation was less than optimal, both from Dominion's perspective and from that of the system as a whole.

In response to these conditions Dominion and SEPA reopened negotiations and arrived at an agreement whereby Dominion would dispatch the entire three-reservoir system, to its economic advantage, while insuring that the requisite energy was delivered to SEPA's customers on schedule, either from hydropower or other resources. The transfer of dispatch responsibilities took place on May 1, 2005, concurrent with Dominion's entry into the Pennsylvania/New Jersey/Maryland Interconnection (PJM) regional transmission market.

In early 2005, as they prepared for May 1, Dominion approached HydroLogics for assistance. HydroLogics was chosen in part because they had already modeled the system in the OASIS[1] application of the basin that had been developed for relicensing. That application, known as the Roanoke River Basin Reservoir Operations Model, covered the entire Roanoke River basin upstream of Roanoke Rapids Dam including not only the three projects of interest here but also the Smith Mountain/Leesville pump/storage project and Philpott Lake. For the economic dispatch application the upstream reservoirs have been removed from the model.

Objective

Dominion's objective for the newly configured system is to maximize revenue from the three dams without violating any of the constraints in its FERC license. In theory, PJM's day-ahead prices reflect the true value of energy delivered to that node. Integrating the Kerr-Gaston-Roanoke Rapids system into that market will, therefore, maximize revenue for Dominion even if it means providing energy to SEPA's customers from other generating assets.

Formulating the Problem Mathematically

As with many of its projects, the Corps' operates Kerr Reservoir according to a guide curve. Although the guide curve has been modified several times since the project went on line, because

---

[1] OASIS is a proprietary water resources simulation/optimization modeling suite developed by HydroLogics, Inc.

Kerr is principally a flood control project the form of the curve has remained substantially unchanged. When the reservoir is above the guide curve the Corps releases more water subject to a fairly standard set of flood control rules. When the reservoir falls below the guide curve, however, the Corps' priority is to deliver "firm energy" to SEPA rather than to preserve lake levels. Firm energy is the minimum amount of energy SEPA guarantees by contract to its preference customers each week.[2] Firm energy varies month by month with the amount for any particular week determined by the month in which Wednesday falls. The monthly firm energy amounts were determined through modeling done by SEPA in the 1980s and based, in large part, on the drought event centered in 1981. SEPA, therefore, expects to purchase energy to meet its contract commitments in drought events more severe than 1981.

In practice, except during flood control the Corps operates Kerr Reservoir on a weekly basis and leaves the day-to-day operations to the power producers, formerly SEPA and now Dominion. The Corps exerts its control by means of a "weekly declaration." On Wednesday of each week the Corps estimates inflows for the coming week (Saturday through Friday) and projects the lake level at the end of the week. If the projected level is at or below the guide curve, the Corps "declares" only the water required to produce the firm energy for the week. If the reservoir is projected to be above the rule curve, the determination is more complex. When the project is not in flood control mode, the Corps decides based on factors such as anticipated inflow, time of year, and unit availability whether to return to the guide curve in one week or to spread it out over two or more weeks.

This method of operation is reliable and easy to understand. But it is sometimes criticized as too mechanistic and insensitive to energy economics.[3] Regardless, from the perspective of formulating a mathematical optimization problem, the declaration concept simplifies things because it removes any uncertainty about the water that will be delivered to Dominion's project over the course of the week.

OASIS formulates system operations as a linear program (LP), a formal optimization technique that is appropriate if the constraints are all linear. In most applications OASIS is used to simulate system operations, and this involves formulating and solving an LP at each time step to determine operations for the next time step. The LP is formulated based on an operating policy prescribed by the user in the form of targets and constraints and prioritized by means of "weights" ("prices" in LP parlance). The operations for that time step are mathematically optimal in that they allocate water in the most efficient manner possible according to the guidance provided by the user. However, this is not the classical optimization problem in which one seeks, as here, to maximize (or minimize) some quantity, such as revenue, over multiple time

---

[2] When the reservoir is above rule curve, the excess water is released as "secondary energy," which is also delivered to the preference customers.

[3] Both SEPA and Dominion have storage accounts that are supposed to address this issue, but they are little used because of the administrative burden associated with using them.

steps. In this application, then, OASIS is being used to solve a classic optimization problem, namely maximizing revenue over multiple time steps subject to several constraints.

There is one weakness in using LP for hydropower scheduling – the problem is inherently nonlinear. Power is the product of head and flow, both of which are decision variables in the LP. However, because of the constraints on this system, it is reasonable to assume that the head is known and to use only the flow as the decision variable. Both Gaston and Roanoke Rapids have a limited range of stages, and they vary about the mean. Under normal conditions they are never off by more than 0.5 ft (<1%) and 2.5 ft (3.5%) for Gaston and Roanoke Rapids, respectively. The head in Kerr is assumed to vary linearly from the starting stage to the projected stage at the end of the optimization period. So for this system the assumption of known heads works well, which makes the problem amenable to solution via an LP.

A more complete articulation of problem is as follows:

Maximize the total revenue from Kerr, Gaston, and Roanoke Rapids for the week

given:

- the volume to be released from Kerr for the week (the declaration)
- starting lake levels in each lake
- a time series of hourly energy prices for the week
- an hourly time series of projected local inflows to Gaston and Roanoke Rapids
- desired lake levels in Gaston and Roanoke Rapids at the end of the week
- an hourly time series of required releases from Roanoke Rapids Lake

subject to:

- maintaining Lake Gaston within 6 inches of elevation 199.5
- maintaining Roanoke Rapids Lake between elevation 127.0 and 132.0
- maintaining the release from Roanoke Rapids Lake at or above the FERC - directed minimum

This is a very common type of LP problem, the mathematical form of which consists of an objective function and a number of constraints. The objective function is as follows:

$$\text{Maximize } Value = Price * Energy$$

where
Value is expressed in dollars,
Price is expressed in \$/MWh, and
Energy is expressed in MWh.

The continuity (mass balance) constraint is written for each reservoir and every hour in the optimization, thus:

Storage(end of hour) = Storage(start of hour) + Inflow(this hour) – Outflow(this hour)

where
Inflow and *Outflow* are expressed in acre-feet/hour, and
Storage is expressed in acre-feet.

Discharge through the turbines is converted to energy with this constraint:

*Energy = 0.00102 * Flow * Head * Efficiency*

where
Flow is expressed in acre-feet/hour,
Head is expressed in feet and assumed constant,
Efficiency is unitless and assumed constant, and
the constant *0.00102* converts volume in acre-feet and head in feet to energy in MWh.

Real-world Application of the Optimal Solution

As described in the previous section, the mathematical formulation of the problem is relatively straight forward. In fact, all of the conditions exist to make this an ideal academic optimization problem. However, in the real world, things do not remain static for a week. Not only do the forecasted prices change from one day to the next, but the weather changes, and streamflows are not predictable. There are also a myriad of other constraints that arise from day to day, ranging from needing to have one of the lakes at a particular elevation at a given time for maintenance to altered releases downstream for any number of purposes. Some of these add-on constraints are known in advance. Unfortunately, many are not. Thus, the following procedure was adopted as the best application of formal optimization techniques to the real world problem at hand.

In the PJM system, day-ahead contracts are essentially locked in at noon the day before. That means that the optimization model must be run using starting conditions, namely lake levels and the declaration remaining, that are predicted to exist more than 12 hours later. The best estimates of those conditions can be obtained by simulating system performance today. Hence the first step each day is to simulate the operations for the day based on the schedule that was awarded yesterday and using the actual lake levels that existed at midnight. In the event that yesterday's predictions of starting conditions were not accurate (i.e., there were problems yesterday), the first step is to evaluate today's schedule with the actual starting conditions and, if needed, adjust today's schedule.

With the predicted starting conditions at midnight in hand, the next step is to run the optimization model for the period through the end of the week using as input the time series of hourly prices, the MWh remaining in the declaration, and the desired lake elevations at the end of the week.[4]

The result of the optimization is an hourly schedule for each plant for the rest of the week along with the predicted hourly lake stages and releases downstream. The schedule is reviewed by operating personnel at the plant in case there are local conditions that would dictate overriding the model's optimal schedule. (The presence of hydrilla, an exotic weed that forms large mats and reduces hydraulic capacity, and rapidly changing dissolved oxygen levels are examples of reasons that the schedule might be overridden.) Only then is the next day scheduled with PJM. Tomorrow, the process starts over again.

This approach works well except during flood events, when the local inflows to the project are hard to predict, and on days when, for some reason, one or more of the projects can not follow the schedule. (This most often happens as a result of transmission constraints or because of mechanical or electrical problems.) On these occasions it is necessary to run the simulation model during the course of the day in order to stay within the limits prescribed by the license. When this happens and to the extent necessary, the projects are run real time using the simulation model for guidance. Dominion enters the unscheduled generation in the real-time market and must compensate PJM for the portion of the schedule that was not run. Essentially, this means that Dominion is buying and selling in the real-time market whenever they deviate from the schedule.

Results

Because three factors (deregulation, assumption of dispatch of Kerr, and adoption of the simulation and optimization models) changed nearly simultaneously, it is impossible to ascertain with certainty the economic benefit that is attributable solely to the use of the models. An approximation is possible, however. In a relatively small system like Dominion's, storage is money because it affords the opportunity to reallocate water from low value hours to higher value hours. As shown in Figures 2 and 3, below, the current methodology routinely allows operation of Lake Gaston within one tenth of a foot and Roanoke Rapids lake within one half of a foot. Of course, some safety buffer is always needed to protect against violations that might be caused by wind setup, the wave associated with upstream releases, or other serendipitous events. Suffice it

[4] Normally it is desirable to have both lakes near-full for the beginning of the work week because prices are usually lower on the weekend, and it would not be economically advantageous to run on the weekend solely to be prepared for Monday. By Wednesday, however, estimated prices are available for the beginning of the next week, so on occasion the target ending elevations are adjusted to better utilize the water between weeks.

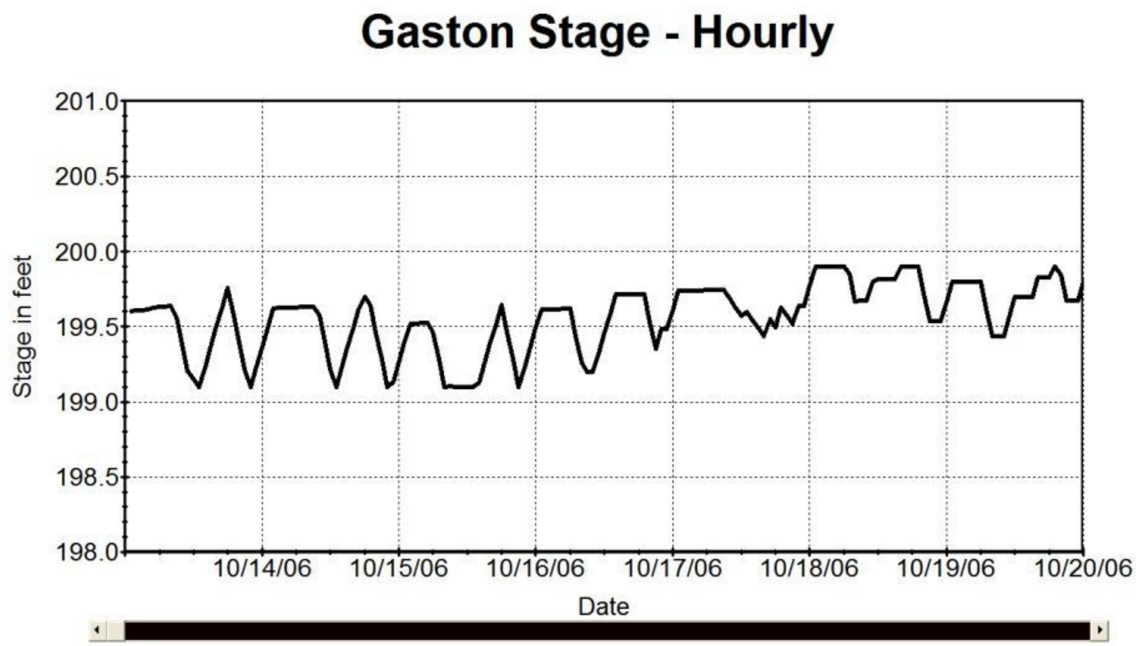


Figure 2. Typical Weekly Storage Plot for Lake Gaston.

Note: The operating range for Lake Gaston is 199.0 to 200.0 feet.

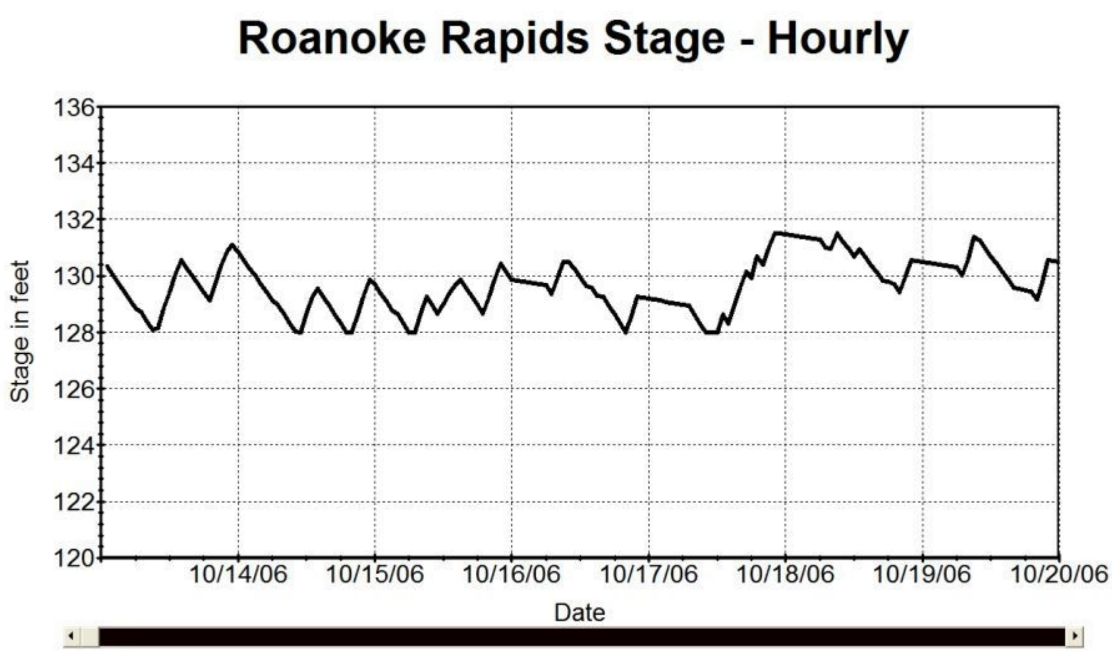


Figure 3. Typical Weekly Storage Plot for Roanoke Rapids Lake.

Note: The spillway elevation at Roanoke Rapids is 132.75 feet, but operations are not scheduled above elevation 132.0. The license limits allow drawdown to elevation 127.0. Because of decreased efficiency, however, elevation 128.0 is considered the normal "bottom."

to say that storage is being used much more aggressively than before. Based on simulation modeling using different fractions of the total storage in the projects, economic dispatch has been significantly improved. Operating the system in an integrated manner rather than as two connected but semi-independent parts also has had an impact. Although not quantifiable without considerable historical analysis, this effect is also likely to be significant.

Remaining Issues

As of early 2007 two additional refinements to the optimization model remain uncompleted. The first has to do with the wave associated with upstream releases. The second is the desire to convert the model's time horizon from one week to two weeks. These will be addressed in turn.

The wave from Kerr varies from approximately 10 feet immediately downstream of the dam to something less than a foot by the time it reaches the Gaston dam. The FERC license directs that the elevation in Lake Gaston be kept between elevations 199.0 and 200.0 at the Gaston dam. Clearly, the failure to properly account for the wave can have serious consequences for license compliance. (Because the allowable fluctuation in Roanoke Rapids Lake is five feet, the wave effect is less of a problem than at Lake Gaston.) The fact that the stage recorder is located inside the weir at the Gaston powerhouse simply exacerbates the issue. (Dominion is investigating having the gage relocated.) The model was originally designed to work on an hourly time step because that is the time step on which energy is marketed. However, for two reasons the hourly time step does not do a very good job of predicting elevations associated with the wave. First, the time of travel is not exactly four hours. Secondly, using an hourly time step and a four-hour travel time means that none of the water released from Kerr shows up until 4 hours later, which is not realistic. The solution to this problem, now in its final testing, is to convert the model to a 15-minute timestep. This is done behind the scenes so that the model still reports energy and releases hourly but the predicted elevations are reported on the finer time step.

The second issue is associated with the inflexibility inherent in operating with a weekly declaration. As currently operated the procedure is fairly inflexible and provides no easy mechanism for moving water a few days ahead to take advantage of higher prices. With few exceptions, since May 1, 2005, Dominion has run the Corps' declaration as closely as possible, returning to the *status quo ante* every week. Even without modifying the declaration, however, and limited by the storage which it controls, Dominion has some ability to reallocate water between weeks. The difference between ending the week empty or full amounts to about 500 MWh that can be moved between weeks. The problem is that PJM forecasts prices only for the next 6 days, so there is no mechanism for evaluating whether water is more valuable this week or next. As currently configured, the model is run on Friday for the week beginning Saturday, on Saturday for the remaining six days, etc. We are constrained to this approach because we do not know until Wednesday what the declaration will be for the next week. For the optimization model to work correctly, the end state (elevations at Friday midnight) must be specified. Thus to improve between-week allocation, there are two problems that need to be solved. One is developing some means of estimating prices out beyond six days. The second is developing a reasonable estimate of next week's declaration. If these problems can be solved the optimization time horizon can be extended to two weeks, which means that the end state is always at least a week away and that the model will determine the most economical allocation of storage between the two weeks. Both issues are currently being pursued, but considerable work remains to determine the degree of accuracy needed if the estimates are to provide real value in reallocating water and whether such accuracy can be achieved.

Conclusions

As noted above, in a hydropower system like Dominion's, storage is money. In this system, storage is so limited that taking full advantage of the opportunities it provides is all the more important. To operate the projects near the license limits without violating them requires modeling tools that capture not only the basic mass balance of water between the projects but also the time of travel between them. Even though this problem represents a textbook case for formal optimization and a "one touch of the button" solution, the results of the weekly optimization do not provide an adequate solution to the real-world problem at hand. To work on an operational time scale, therefore, we have crafted an approach involving an iterative use of both simulation and optimization models on a daily (and sometimes more frequent) basis. That is, the optimal solution is not the decision. Rather, it informs the decisions that must be made throughout the week. This approach has given operators much more confidence in their ability to take advantage of all of the usable storage without fear of violating the FERC license and has resulted in considerable additional revenue for Dominion.

Authors

Brian J. McCrodden, P.E., is Vice President and Business Manager of HydroLogics, Inc., in Raleigh, North Carolina. He has worked extensively on the Roanoke River and was the Principal-in-Charge of this project.

Dean Randall, Ph. D., P.E., is a Senior Supervisory Engineer with HydroLogics, Inc., in Columbia, Maryland. He formulated the linear program for this application of OASIS.

James W. Thornton is a Technical Consultant with Dominion Virginia Power in Richmond, Virginia, and was the relicensing manager for the Gaston and Roanoke Rapids project.