Influence of Deregulated Electricity Markets on Hydropower Generation and Downstream Flow Regime

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Abstract: The flow regime of rivers is a complex but important measure of environmental quality and one that can be significantly impacted by conventional hydropower generation. While traditional hydropower scheduling creates a periodicity in downstream flows corresponding to seasonal and daily electricity demand patterns, deregulated electricity markets may provide financial incentives to further alter flows, as utilities respond to hourly market dynamics. This study investigates the potential for deregulated markets to impact both a hydropower utility's revenue stream and downstream flow regimes. Six operating scenarios are explored: (1–2) full-market participation (including real-time energy), with and without flow reregulation; (3) day-ahead market only; and (4–6) run-of-river operations (ROR), with and without flood control and flow reregulation. Results suggest that, relative to a day-ahead-only scenario, the scale of any differences in flow regime resulting from full-market participation is relatively small compared to the additional revenue-generating potential of such a strategy. Implementing a run-of-river policy frequently yields "more natural" flow regimes than the day-ahead only scenario; but, in some cases these improvements are modest, and in others the ROR scenarios exacerbate deviation from unregulated flows. Regardless, the effects of implementing an ROR strategy come at a substantial cost in terms of foregone hydropower revenue. **DOI: 10.1061/(ASCE)WR.1943-5452.0000183.** *© 2012 American Society of Civil Engineers.*

CE Database subject headings: Ecosystems; Flow simulation; Hydro power; Rivers and streams; Electric power.

Author keywords: Ecosystems; Flow simulation; Hydro power; Rivers; Electric power.

Introduction

Efforts to reduce pollution and lower greenhouse gas emissions will benefit from an increased reliance on renewable energy production. In 2008, hydropower accounted for 67% of U.S. renewable electricity generation and 6% of total U.S. generation [Energy Information Agency (EIA) 2008]. While significant, these numbers understate the importance of hydropower as an energy storage mechanism and a peaking resource. On timescales that range from minutes and hours to seasonal, hydroelectric dams can store water (i.e., potential energy) when electricity demand is low and release water when demand is high. In addition, the low variable costs of hydropower production and its minimal ramp-up time mean it can be used to respond to short-term changes in electricity supply and demand more rapidly and less expensively than thermal generators (e.g., coal, nuclear, and natural gas) [National Academy of the Sciences (NAS) 2010]. These advantages also make hydropower a useful complement to more intermittent renewable energy sources, such as solar and wind [Dept. of the Interior (DOI) 2005].

Although hydroelectric dams have many positive aspects, concerns over their environmental impacts have motivated efforts to restore or improve rivers by reducing hydropower generation, or, in some cases, removing dams altogether (Babbitt 2002; Hart and Poff 2002). Consequently, there is a critical need for understanding the trade-offs between hydropower generation and environmental quality, as well as methods for integrating this knowledge into the development of more sustainable natural resource management strategies.

Previous attempts to characterize the impacts of hydropower generation on environmental quality include investigations of effects on riparian vegetation (Auble et al. 1994; Nilsson et al. 1997; Townsend 2001) and downstream geomorphology (Ligon et al. 1995; Shields et al. 2000; Shields et al. 2010), as well as macroinvertebrate and fish communities (Gorman and Karr 1978; Suen et al. 2009; Poff and Zimmerman 2010). A subset of this research has focused on how dams alter the natural flow regime of rivers (Poff et al. 1989; Richter et al. 1996; Poff et al. 1997; Matthews and Richter 2007; Vogel et al. 2007), where flow regime is defined in terms of the magnitude, duration, frequency, rate of change, and timing of river flows. Collectively, these five categories are considered to comprise a master ecological variable that influences the abundance and distribution of species within lotic ecosystems (Power 1995). Efforts to develop explicit relationships that connect the type and degree of flow alteration with specific ecological responses are ongoing; however, a significant body of research shows that disrupting the natural flow of rivers can result in decreases in biological diversity and abundance, while impacting a number of other ecological parameters (Poff and Zimmerman 2010). Previous research has also begun to explore the short-run economic cost of

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Note. This manuscript was submitted on November 11, 2010; approved on August 1, 2011; published online on August 6, 2011. Discussion period open until December 1, 2012; separate discussions must be submitted for individual papers. This paper is part of the ***Journal of Water Resources Planning and Management***, Vol. 138, No. 4, July 1, 2012. ©ASCE, ISSN 0733-9496/2012/4-342–355/$25.00.

imposing environmental restrictions on the ways in which hydroelectric dams are typically operated (Edwards 1999; Harpman 1999; Kotchen et al. 2006; Jager and Bevelhimer 2007). These types of studies can provide policymakers with tools to assess the costs and benefits of river management strategies. Nonetheless, past attempts to characterize trade-offs between hydropower generation and ecosystem quality have yet to address a more recent and potentially important development.

Recent regulatory changes have resulted in the emergence of deregulated electricity markets (Rothwell and Gomez 2003), a new institutional arrangement that incentivizes utilities to optimize power production according to hourly and real-time electricity price dynamics. Electric utilities that participate in deregulated electricity markets experience hourly fluctuations in market prices, with price volatility amplified by the difficulty of storing electricity. Since hydropower can be used to quickly respond to changes in market prices, dam releases (and thus river flows) may increasingly be linked to deregulated market behavior. As such, there is a need to explore the connections between deregulated electricity markets, hydropower generation, and downstream environmental quality.

This study investigates the potential for participation in a deregulated electricity market to impact both a hydropower utility's revenue stream and downstream flow regimes. Particular attention is paid to the scale of these effects when comparing the following six scenarios to unregulated flows (dam removal): (1–2) full-market participation (with and without flow reregulation), in which the utility exploits multiple deregulated markets (including real-time energy); (3) day-ahead market only (similar to operations in a regulated market); and (4–6) three different run-of-river (ROR) scenarios (which allow natural inflows to determine daily power generation). Hydropower operations at a three-dam cascade in the Roanoke River basin (mid-Atlantic region of the United States) are used to evaluate these six scenarios over the period August 2005–August 2010. Flow regime statistics that reflect environmentally critical components of river flow are used to assess relative differences in downstream flows across the scenarios. These are then compared with the relative differences in hydropower revenues resulting under each.

Deregulated Hydropower

Deregulated electricity markets emerged in the United States during the late 1990s and primarily operate today in the Southwestern and Eastern regions of the country, as well as along the West Coast. In traditional regulated markets, electric utilities primarily sell wholesale and retail power at fixed rates over a single geographical area. Hydropower, due to its low cost and quick ramp-up time, is typically used by regulated utilities to respond to unexpected capacity losses, regulate grid frequency, and meet peak demands. In deregulated markets, the financial opportunities for utilities with hydropower assets are greatly enhanced, with more buyers in more markets.

PJM Energy and Frequency Regulation Markets

The electricity market considered in this paper is PJM Interconnection, which coordinates the operation of an extremely large electrical grid and deregulated electricity market spanning much of the Mid-Atlantic region of the United States Members of PJM can buy and sell electricity in both the day-ahead and real-time energy markets. In the day-ahead market, participants submit sell/bid offers for electricity for each hour of the following day. These offers consist of a quantity of energy (MWh) to be sold or purchased, and a desired price (US$/MWh), where sell-offers correspond roughly to each generator's marginal cost of energy production. For each hour of the following day, PJM then ranks sell-offers from least to most expensive; the last sell-offer required to satisfy day-ahead forecasted demand clears the market, and the marginal cost of increasing power supply by one additional MW determines the market-clearing energy price. Sellers with offers equal to or below this price then generate revenue equal to their respective bid quantities multiplied by the market-clearing price. (Rothwell and Gomez 2003).

Most generation sold in PJM is done via the day-ahead market or bilateral transactions (PJM Interconnection 2010); but power producers have also begun to position themselves to take advantage of new opportunities afforded by deregulation. Throughout the operating day, PJM coordinates an hourly real-time energy market, which is used to meet real-time electricity demand when it varies relative to day-ahead forecasts. An hourly, real-time market-clearing price is determined in a manner similar to the day-ahead market (i.e., via the ranking of bid/sell-offers), and transactions are consummated as necessary to meet real-time demand (Lambert 2001).

In addition to operating day-ahead and real-time energy markets, PJM also coordinates market-based pricing of various ancillary services, which support the reliable operation of the electrical grid as it moves electricity from power producers to retail customers. Three different types of ancillary services markets are operated by PJM; of these, frequency regulation service, which corrects for short-term changes in grid electricity use that may cause the power system to operate above or below the standard of 60 Hz, is the only one considered in this study (synchronized reserve and black start service are the other two) (PJM Interconnection 2010).

In the regulation service market, sellers agree to (if called upon) increase or decrease generation by an incremental amount (MWh) specified in their respective sell-offers. The PJM market maintains hourly, gridwide requirements for regulation service capacity. Each load-serving entity is responsible for providing regulation service capacity equal to 1% of its day-ahead forecasted demand. These utilities can satisfy their individual requirements using their own generation assets, bilateral agreements with other utilities, or by buying regulation service via the market. Potential regulation service providers submit hourly sell-offers on a day-ahead basis, and the market-clearing price for regulation service for any given hour is then set in real-time by the last sell-offer required to meet gridwide demand. Fig. 1 shows an example of a decision-making timeline for participation in both the day-ahead and real-time energy markets, as well as the regulation service market (PJM Interconnection 2010).

An important characteristic of deregulated electricity markets is hourly fluctuation of prices. In general, the day-ahead market operates in a manner that maintains a relatively low level of real-time price volatility by scheduling as much generation as possible 24 h in advance. But price volatility in the real-time energy market is inevitable due to short-term, unexpected changes in supply and demand. For the period August 2005–August 2010, the price in the day-ahead energy market was higher than it was in the real-time energy market about 70% of the time (PJM Interconnection 2010); however, during the other 30%, real-time energy prices were higher, and 1–2% of the time real-time energy prices spiked to very high levels (e.g., August 8, 2007, when the price of electricity briefly spiked from average retail levels of US$90/MWh to over US$1,000/MWh). The short duration (a few hours) of these price spikes is a common aspect of deregulated electricity markets and one that is generally characteristic of price behavior for nonstorable commodities experiencing short-term changes in demand (Huisman and Mahieu 2003).

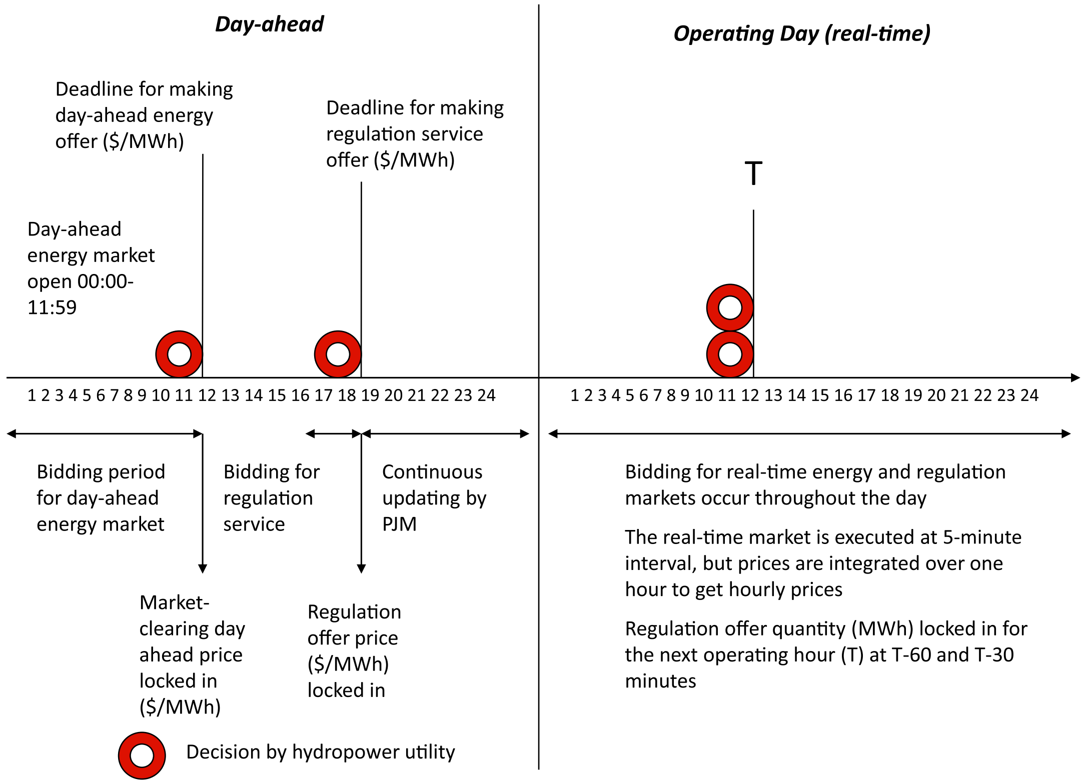

Fig. 1. Decision-making timeline for modeled hydropower utility selling in the PJM energy and regulation service markets

Methods

Investigation of the relationship between deregulated market behavior, hydropower generation, and downstream flow regime is explored by defining a range of dam-operating scenarios and comparing these with an unregulated flow scenario (i.e., no dams). Six different regulated operational scenarios are described: (1–2) full-market participation (including real-time), with and without flow reregulation; (3) day-ahead only; and (4–6) run-of-river, with and without flood control (FC) and flow reregulation. These are intended to a represent a reasonable range of potential operating scenarios with dams in place. The full-market participation scenario represents one operational extreme by assuming that a utility uses improved information regarding real-time prices and forecasted demand to take advantage of both the day-ahead and real-time energy markets (and the regulation service market). The day-ahead only scenario represents a strategy similar to traditional hydropower operations in a regulated market, i.e., simply matching hourly releases with peak demand hours. The run-of-river (ROR) scenarios are collectively presumed to be a lower environmental impact approach, in which daily releases are dictated by reservoir inflows. In one ROR scenario, the dam is still operated to meet water supply and flood control objectives; in the other, reservoir outflows are forced to equal inflows as long as the reservoir is full. Flow reregulation is a multireservoir strategy that involves capturing flows resulting from upstream hydropower generation and rereleasing this water in a manner that mimics natural inflows.

Each regulated scenario consists of different linked models of basin hydrology (a daily water balance) and hourly power generation; the unregulated scenario consists of a hydrologic model only. Each hydrologic model simulates daily storage and flow values at a dam site. Model inputs include historical records of runoff, evaporation, and precipitation. Dam-operating specifications for each reservoir include storage-area-elevation curves, head differentials, dam turbine capacities, turbine-generating efficiencies, reservoir guide curves, seasonal water supply demands, minimum flow requirements, and generation commitments.

For each regulated scenario, output from the hydrologic model (i.e., daily reservoir storage and discharge values) is used as input for a power generation model that simulates hourly operations. Given a set volume of water to be released in a given period, the power generation model maximizes the number of hourly hydropower releases made at turbine capacity. With the exception of hours that precede real-time dam releases, the power generation model also schedules water for ramping hours (hours of intermediate flow surrounding high release periods).

Operating Horizon and Demand Forecasts

Several important aspects of a utility's decision-making process are addressed, including the ability to use projected inflows and electricity demand forecasts in scheduling hydropower generation. This ability is simulated using historical PJM demand forecasts, as well as a designated operating horizon, a term used to represent the number of consecutive days of projected inflows and demand forecasts that a utility incorporates into its hourly decision-making process. Depending on its length, the operating horizon augments (or limits) a utility's ability to consider information about future periods when scheduling hourly generation. From a modeling perspective, the operating horizon is the number of consecutive days' cumulative discharge (from the hydrologic model) and demand forecasts that are used to schedule hourly generation.

It is important to note the difference between this study's use of forecasted demand information and that which is actually available to utilities in PJM. Most utilities would initially schedule generation at a dam using a full 7-day demand forecast and continually revise their release schedules as the week progresses and updated

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demand and inflow forecasts become available. However, since historical multiday demand forecasts are not publically available from PJM, the power generation models in this study use historical day-ahead demand forecasts (which are available). These forecasts include a lower level of uncertainty than the multiday advance demand forecasts used by utilities in PJM, but the difference is relatively small, with weather forecasting often serving as the greatest source of error in power demand forecasts (Brattle Group 2006).

Day-ahead Market Only

For each operational scenario, the decision rules regarding how to allocate water over the specified operating horizon are dictated by the markets in which the dams are participating. Day-ahead market participation means hourly hydropower generation is scheduled over the operating horizon according to hourly, day-ahead forecasted demand in the PJM market (similar to traditional hydropower operations in a regulated market). Each hour of the operating horizon (e.g., a 4-day operating horizon would have 96 ranked hours) is ranked in terms of its forecasted demand. Given the cumulative discharge over the operating horizon, this volume of water is allocated one hour at a time (at turbine capacity) in order of decreasing forecasted demand.

Full-Market Participation

Full-market participation is designed as one extreme of the operational scenarios possible with dams in place. As such, it makes some assumptions regarding the degree to which a utility can accurately anticipate high real-time prices in advance. However, due to the rapid execution of the real-time market (5 min) and the significant strides made by real-time price models (Aggarwal et al. 2009), full-market participation remains a reasonable (if hypothetical) upper bound regarding the impact that deregulated markets could have on flow regime.

First, cumulative discharge values for the operating horizon are combined and allocated on an hourly basis for generation in the day-ahead energy market, similar to the process followed for the day-ahead only scenario. The second step involves participation in the regulation service market, in which utilities offer their capacity to quickly increase or decrease generation during one hour [specifying the amount (MWh) and price (US\$/MWh)], if called upon by the system operator. For each dam under consideration, a static hourly regulation sell-offer of $+/-10$ MWh is assumed, and the actual net regulation service called for by PJM in each hour is calculated using a random number generator over the interval. Similar to the day-ahead and real-time energy markets, a regulation market-clearing price is determined (on an hourly basis) by the last sell-offer needed to satisfy gridwide demand. The decision to participate in the regulation market must be made on a day-ahead basis, with no knowledge of the regulation market-clearing price or the nature of the regulation signal (up or down). As a result, it is assumed that the utility will only participate in the regulation market during those hours where hydropower generation is already scheduled for sale in the day-ahead market.

The third step in the full-market participation scenario allows the utility to deviate from its initial day-ahead generating schedule in order to take advantage of price increases in the real-time energy market. For any given hour of the week, if: (1) there is no day-ahead generation scheduled; and (2) the real-time price of electricity is predicted to be above the 95th percentile of the historical distribution (US\$144.50/MWh), then the utility participates in the real-time energy market. This is accomplished by borrowing water from the lowest-ranked (in terms of forecasted demand), scheduled release in the day-ahead market for the remaining days of the operating horizon, thus shifting generation forward to when it is more

Table 1. 32 Indicators of Hydrologic Alteration (IHAS) and Environmental Flow Components (EFCS) Used in This Study

IHA flow metric	Category	Environmental flow components
12 monthly mean flow (kL/s)	Magnitude, timing	
1-day minimum flow (kL/s)	Magnitude, duration	Extreme low flows:
1-day maximum flow (kL/s)	Magnitude, duration	Frequency, magnitude
1-day minimum flow date (1-365)	Timing	Timing, rate of change, duration
1-day maximum flow date (1-365)	Timing	
3-day minimum flow (kL/s)	Magnitude, duration	Low flows:
3-day maximum flow (kL/s)	Magnitude, duration	Frequency, magnitude
7-day minimum flow (kL/s)	Magnitude, duration	Time, rate of change, duration
7-day maximum flow (kL/s)	Magnitude, duration	
30-day minimum flow (kL/s)	Magnitude, duration	High flow pulses:
30-day maximum flow (kL/s)	Magnitude, duration	Frequency, magnitude
90-day minimum flow (kL/s)	Magnitude, duration	Timing, rate of change, duration
90-day maximum flow (kL/s)	Magnitude, duration	
Number of low pulses[a]	Magnitude, frequency, duration	Small floods:
Number of high pulses[b]	Magnitude, frequency, duration	Frequency, magnitude
Low pulse duration (days)	Magnitude, frequency, duration	Timing, rate of change, duration
High pulse duration (days)	Magnitude, frequency, duration	
Number of falls	Frequency, rate of change	Large floods:
Number of rises	Frequency, rate of change	Frequency, magnitude
Average fall rate (cfs/day)	Frequency, rate of change	Timing, rate of change, duration
Average rise rate (cfs/day)	Frequency, rate of change	

Note: See Richter 1996; Matthews and Richter 2007.
[a]Defined as daily flow values ≤ the 25th percentile of unregulated flows.
[b]Defined as daily flow values ≥ the 75th percentile of unregulated flows.

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valuable. The selection of the cut-off point was based on sensitivity analysis in which revenues were calculated using a range (85th–99th percentile) of potential real-time price thresholds, with the 95th percentile yielding the greatest total revenue over the five years considered.

There are noteworthy differences in the way that revenues are calculated for regulation service. For example, if a utility sells 10 MWh of capacity in the regulation service market, and PJM requires that utility to increase its net generation +7 MWh over one hour, the utility will earn the following amount:

$$O_{\mathrm{DAS}} \times P_{\mathrm{DA}} + 10\ \mathrm{MW} \times P_{\mathrm{RM}} + 7\ \mathrm{MWh} \times P_{\mathrm{RT}} \quad (1)$$

where O_{DAS} = day-ahead sale offer (MWh); P_{DA} = day-ahead energy price (US\$/MWh); P_{RM} = regulation market price (US\$/MW); and P_{RT} = real-time energy price (US\$/MWh)

If, however, the utility is instructed to decrease net hourly generation by 7 MWh, it would only earn revenue from the regulation and day-ahead energy markets

$$(O_{\mathrm{DAS}} - 7\ \mathrm{MWh}) \times P_{\mathrm{DA}} + 10\ \mathrm{MW} \times P_{\mathrm{RM}} \quad (2)$$

In the case of decreased generation, however, the water that is not used is still available to generate power at a future time.

Run-of-River

Two run-of-river (ROR) operating strategies (one that considers flood control and one that does not) were designed to serve as a lower bound on dam operations in terms of environmental impact. For run-of-river without flood control, downstream flows are expected to more closely mimic unregulated flows by enforcing daily adherence to a flat reservoir guide curve (outflows equal inflows). An additional ROR scenario was also developed, in which the ability to force outflows equal to inflows is limited by a requirement that the reservoir volume be maintained at a level consistent with flood control objectives (a seasonal guide curve).

Power generation for both ROR scenarios is simulated assuming hourly releases are made in accordance with a 1-day operating horizon and day-ahead forecasted electricity demand, and, within this context, used to maximize daily generating revenues. These scenarios involve no participation in the real-time or regulation service markets.

Flow Reregulation

In areas where multiple dam sites are located upstream from sensitive ecosystems, there is considerable interest in exploring how regulating flow at only the furthest downstream dam might impact flow regime and hydropower revenues. In such a strategy, reservoir levels at upstream sites are allowed to fluctuate, but the downstream dam maintains a daily outflow proportional to inflows at the furthest upstream dam, and hourly flows are kept relatively constant (no peaking). Flow reregulation is added to the ROR scenario without flood control to form a presumed "lowest-impact" scenario; it is likewise added to full-market participation as an attempt to mitigate that strategy's negative impacts on downstream flow regime.

Indicators of Hydrologic Alteration

Indicators of hydrologic alteration (IHAs) are used to describe the flow regime resulting from each modeled scenario. These are a group of 32 flow statistics (Table 1), subdivided into five categories of flow: magnitude, duration, timing, frequency, and rate of change. They were developed in order to quantify the degree of hydrologic alteration resulting from a particular disturbance in a river basin, such as changes in land use or a dam (Richter 1996). Each category has been posited to have direct biological and ecological significance (Poff 1997), such that significant changes in flow regime may lead to significant impacts on downstream riparian

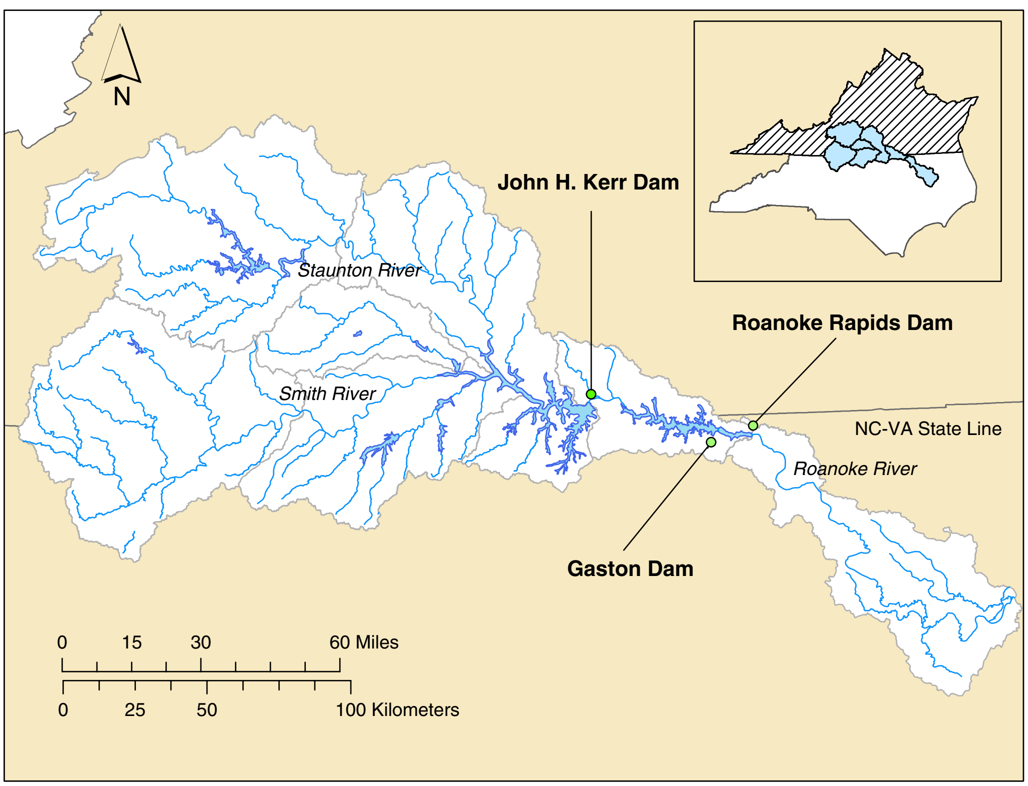

Fig. 2. Roanoke River Basin of North Carolina and Virginia

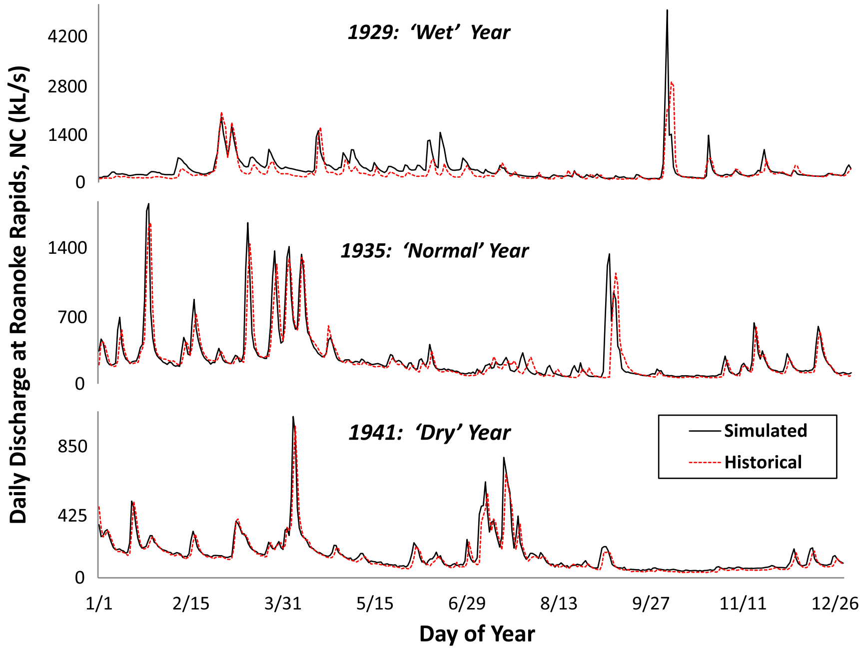

Fig. 3. Simulated and historical unregulated flow in select years

ecosystems. Nonetheless, despite continuing research, connecting changes in flow regime to specific biological and ecological endpoints is an ongoing challenge (Poff and Zimmerman 2010); this work will therefore focus on evaluating changes in these IHAs relative to unregulated conditions, using these differences as a surrogate for environmental impacts.

Principal Components Analysis

Previous efforts to develop representative environmental flow metrics have included attempts to address IHAs' intercorrelation and redundancy (Gao et al. 2009). From an environmental policy perspective as well, it may be preferable to focus on a smaller number of the most relevant metrics. Principal components analysis (PCA) is used to select a subset of the most significant IHAs in a manner similar to that used by Gao et al. (2009). Input data are stored in an $N \times 32$ matrix corresponding to 32 mean-centered IHA statistics for N-years of unregulated flow data. Decomposition of the associated covariance matrix into eigenvectors ranked by eigenvalue yields a set of principal components. The highest loaded variable (IHA) in each eigenvector is deemed a reasonable proxy for each respective principal component. In some cases the second-highest loaded variable can be chosen in order to avoid selecting the same IHA twice. This process yields a subset of IHAs, which are collectively assumed to explain most of the variation in unregulated flow. Values for each are calculated for each year under the six regulated scenarios and compared in terms of deviations from unregulated flows.

Environmental Flow Components

There is some risk that while the IHAs selected using PCA are statistically important in characterizing unregulated flows at a site, they may not be as ecologically important. To address this shortcoming,

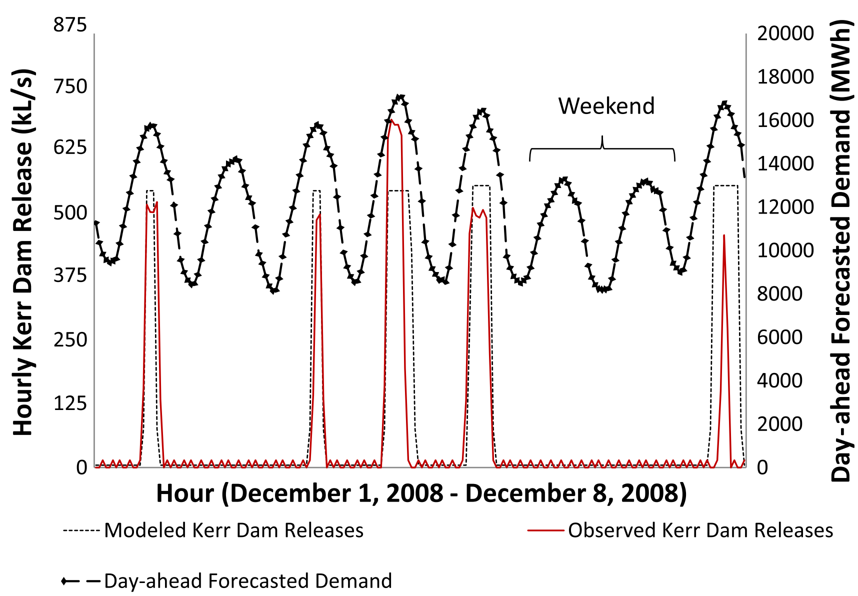

Fig. 4. Modeled day-ahead only (current operations) scenario versus observed hourly Kerr Dam releases

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environmental flow components (EFCs) (Table 1) were developed (Matthews and Richter, 2007) as an addendum to IHAs. These additional statistics focus on quantifying the magnitude, duration, frequency, timing, and rate of change of extremely low flow events (<10th percentile of daily flow values), high flow pulses (>75th percentile of daily flow values), small (2-year) flood events, and large (10-year) flood events. Each represents a unique ecological forcing that may be critical to the ecological integrity of downstream areas. The EFCs are calculated for each scenario and 3-month season (winter: Dec. 1–Feb. 28; spring: March 1–May 31; and so on).

Due to the widespread availability of daily flow data, the development (and use) of IHAs and EFCs in previous studies (and this one) have focused on characterizing flows with a maximum temporal resolution of one day, which may be insufficient for capturing the hourly variations possible in a full-market scenario, as will be discussed later.

Case Study: Roanoke River Basin

The Roanoke River basin (Fig. 2) flows southeast from the Blue Ridge escarpment in Virginia to the Albemarle Sound in North Carolina. The Lower Roanoke River basin includes three hydroelectric dams in close proximity, the largest being John H. Kerr Dam, which is owned by the U.S. Army Corps of Engineers and was completed in 1953. The powerhouse at Kerr Dam has a total installed generating capacity of 206 Megawatts (MW) and a turbine flow capacity of roughly 991.1 kL/s (35,000 ft^3/s). Immediately downstream (about 30 miles) from Kerr Dam is Gaston Dam [generating capacity: 224 MW; turbine capacity: 1,245.9 kL/s (44,000 ft^3/s)], built in 1963, which is owned and operated by Dominion, an investor-owned energy utility. Downstream from Gaston Dam (about 8 miles) is Roanoke Rapids Dam [generating capacity: 104 MW; turbine capacity: 566.3 kL/s (20,000 ft^3/s)], built in 1955, and also owned by Dominion. In general, due to constraints on reservoir level fluctuations at Gaston Dam and Roanoke Rapids Dam, the timing and magnitude of hydropower releases made at Kerr Dam largely dictate the schedule of releases at the two downstream dams. There is very little free flowing river between Kerr Dam and the Gaston reservoir and essentially no free flowing river between Gaston Dam and Roanoke Rapids Reservoir. As a result, operations at all three dams are modeled synchronously (i.e., there is no delay between a release at Kerr Dam and the availability of that water for release at Gaston Dam), with attention to environmental impacts focused on the long stretch of free flowing river downstream of Roanoke Rapids Dam.

This downstream area includes one of the largest and least-fragmented river swamp forest ecosystems remaining in the eastern United States (Lynch 1981). This area and its floodplain have been identified as critical resources for the conservation of bottomland hardwoods and other riparian and in-stream biota (Pearsall et al. 2005). Numerous studies have explored the range of impacts that river flow regulation (i.e., dams) has had on the ecosystems of the Lower Roanoke River basin (Cobb 1990; Richter et al. 1996; Konrad 1997; Rice and Peet 1997; Richter et al. 1997;

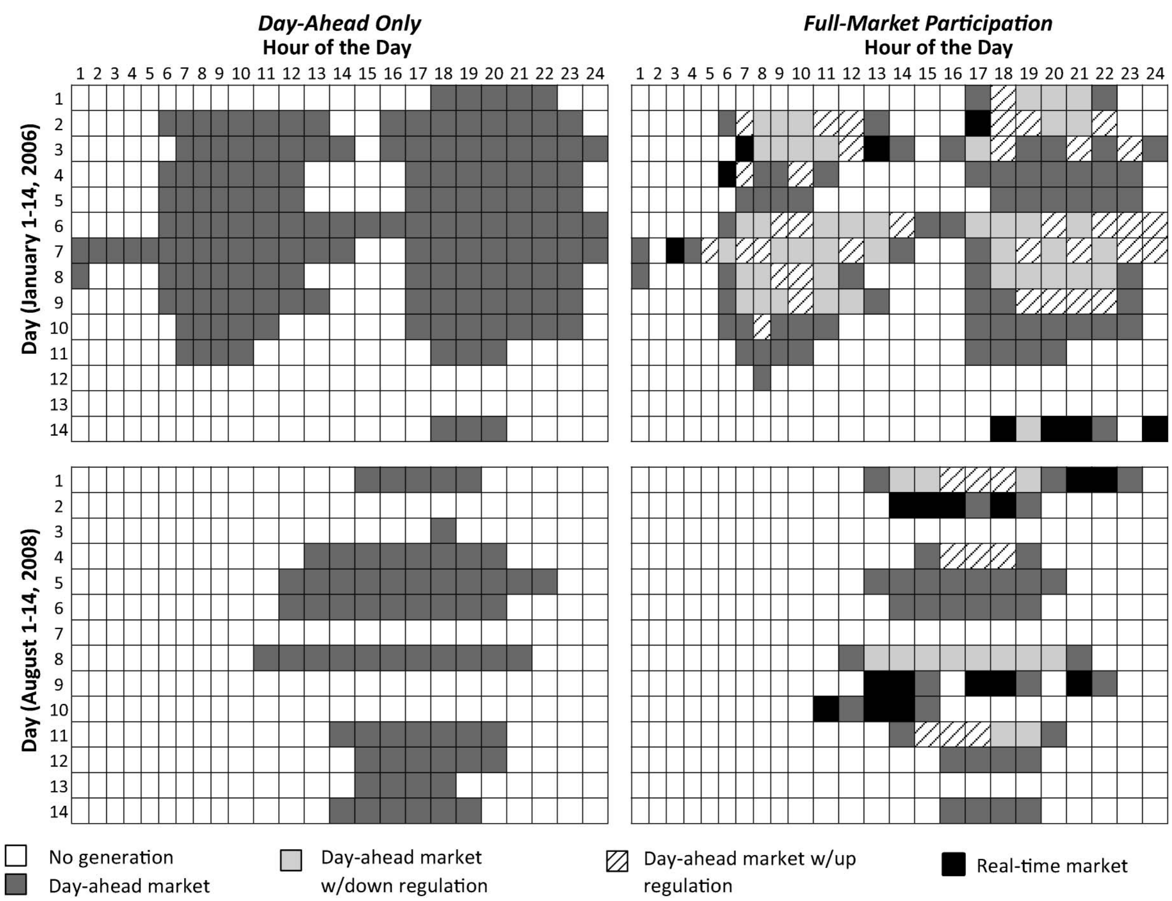

Fig. 5. Modeled hourly market participation for hydropower generated at Roanoke Rapids Dam under day-ahead only and full-market participation for two periods in winter and summer; White boxes signify Roanoke Rapids discharge of 9.2 kL/s (325 cfs) (Federal Energy Regulatory Commission minimum flow constraint)

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Table 2. Generation and Revenue Calculations for Modeled Scenarios

		Full-market participation	Revenue (US$M)				Full-market participation reregulated	Revenue (US$M)			
Year	Hydrologic condition	Generation[a] (GWh)	Day-ahead	Real-time	Regulation	Annual	Generation[a] (GWh)	Day-ahead	Real-Time	Regulation	Annual
2006	Normal	778.4	59.3	19.5	1.6	80.4	729.6	57.2	16.5	2.1	75.8
2007	Dry	1,166.7	73.0	12.5	1.7	87.2	1,072.4	70.2	10.9	2.1	83.2
2008	Normal	562.2	44.2	24.0	1.2	69.4	533.2	43.3	19.9	1.3	64.5
2009	Normal	845.0	47.6	5.8	1.0	54.4	782.5	45.2	5.0	1.3	51.6
2010	Normal	1,470.5	82.0	4.4	1.1	87.5	1,353.1	79.8	3.8	1.3	84.9
	Total	4,822.8	306.1	66.2	6.6	378.8	4,470.8	295.7	56.1	8.2	360.0
		Day-ahead only	Revenue (US$M)				Run-of-river with flood control	Revenue (US$M)			
2006	Normal	768.1	71.8			71.8	762.9	65.1			65.1
2007	Dry	1,152.3	78.0			78.0	1,070.2	65.6			65.6
2008	Normal	558.4	62.0			62.0	552.2	52.1			52.1
2009	Normal	837.8	50.3			50.3	809.5	44.5			44.5
2010	Normal	1,466.0	84.0			84.0	1,259.7	65.4			65.4
	Total	4,782.6	346.1			346.1	4,454.5	292.6			292.6
		Run-of-river (without flood control)	Revenue (US$M)				Run-of-river Reregulated	Revenue (US$M)			
2006	Normal	758.8	64.4			64.4	564.9	61.9			61.9
2007	Dry	1,063.1	65.6			65.6	807.8	63.6			63.6
2008	Normal	545.0	49.1			49.1	403.7	47.4			47.4
2009	Normal	805.2	43.6			43.6	605.1	42.6			42.6
2010	Normal	1,249.8	64.4			64.4	960.0	63.6			63.6
	Total	4,421.9	287.1			287.1	3,341.5	279.2			279.2

[a]1 GWh = 1,000 MWh.

Townsend and Walsh 1997a, b; Butler 1998; Hochman 1999; Hochman 2000; Graham and Cannon 2000; Pearsall 2005). In particular, extended duration high flow events during the growing season have been identified as damaging to seedling survival and ground nesting habitat for birds (Pearsall 2005). However, all of these studies predate the advent of deregulated electricity markets and the potential impacts they may have on flows.

Deregulated Electricity in the Roanoke River Basin

The total volume of water available to be released from Kerr Dam during any given week is established by the U.S. Army Corps of Engineers (USACE) and based on factors related to current storage, recent (and predicted) inflows, and maintenance of flood storage capacity. Until 2005, the timing of hourly (within-week) releases at Kerr was also determined by the USACE, which coordinated hydropower generation at the Dam with periods of high electricity demand for designated federal power customers. However, since May 2005 the scheduling of hourly releases at Kerr Dam has been largely determined by Dominion, which relays release requests directly to Kerr Dam, even as the total weekly volume available for release is still set by the USACE (Whisnant 2009). This change has been concurrent with Dominion's active participation in PJM Interconnection.

Hydrologic Model Performance

Input data to the Roanoke River basin hydrologic models were provided by the North Carolina Department of Water Resources. While many of the dams' operating specifications were taken from the Roanoke River Basin Operations Model (RRBROM), developed by HydroLogics, Inc. in 2005 (NCDENR 2012), the hydrologic model used in this work was developed independently with model validation focused on reproducing historical flows under regulated and unregulated conditions. Simulated daily flows from the unregulated model for the years 1929–1946 were compared to historical predam flows over the same period to assess model performance. This comparison revealed an excellent fit between modeled and observed flows (Fig. 3).

Principal components analysis was performed using 82 years of simulated unregulated flow data (1929–2010) to select seven IHAs whose associated principal components collectively explain 84.5% of the variation in unregulated flows. In addition, values for 20 additional EFCs were calculated under unregulated conditions.

The day-ahead only and full-market participation scenarios share the same hydrologic model. Validation of this model focused on Kerr Dam because of historical data availability. Interest in how dam operations vary with hydrological conditions led to the examination of reservoir operating practices during dry, wet, and normal years (with these climatic distinctions made based on 12-month standardized precipitation indices from the North Carolina Climate Center (2010). In general, the hydrologic model tracks observed reservoir storage at Kerr Dam very well, but does so best during dry and wet years. This is perhaps a function of the very specific dam operating guidelines that exist during very dry and wet periods. Operations during normal hydrologic periods are subject to fewer operating constraints, thereby allowing more operator discretion and making them more difficult to model.

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Power Generation Model Performance

The volume of water available for release from Kerr Dam in a given week is set by the USACE. This constraint is simulated in the power generation model by combining output from the hydrologic model (i.e., daily discharge values from Kerr Dam) into 7-day intervals, yielding cumulative discharge values for days 1–7, 8–14, etc., throughout the year. The power generation model then takes the cumulative discharge values for each 7-day interval and allocates that volume over the week. Generating efficiencies for Gaston and Roanoke Rapids Dams are assumed to be static due to their narrow storage constraints, while the generating efficiency of Kerr Dam is a function of reservoir storage at the beginning of each operating horizon.

Simulating current operations in the basin focused on replicating observed hourly releases at Kerr Dam and IHAs below Roanoke Rapids Dam for the period 2006–2010. Results strongly suggest that Dominion's current operations are mostly limited to the day-ahead energy market, which is not dissimilar to the manner in which many dams have traditionally been operated in regulated markets. The primary reason for this is the current designation of these dams as capacity resources within PJM; while this practice temporarily precludes operation in the real-time energy market, it is conceivable that a strategy analogous to full-market participation could be pursued in the future provided it were consistent with each dam's license.

In order to characterize Dominion's current operations, generation release schedules were simulated under various combinations of operating horizon and level of market participation. Observational data used to develop the power generation model (PJM market prices and day-ahead demand forecasts) were limited to the five years in which these dams have been a part of PJM. In order to maximize use of this data set, a water year is defined in this study to be the period from August of one year to July of the following year. Comparison of simulated results with historical observations (Fig. 4) via a root-mean squared difference approach strongly suggests that over this period these dams largely participated in the day-ahead market only, with the best model fit occurring with use of a 4-day operating horizon. These two parameters are therefore used to characterize the power generation behavior under current operations. For the remainder of this paper, Dominion's current operations are considered synonymous with "day-ahead only" (DA).

As a second method for model validation, observed daily flows at Roanoke Rapids Dam (i.e., historical current operations) were analyzed in terms of the seven IHAs selected and compared with flows from the modeled day-ahead-only scenario as a measure of model fitness. Results suggest a reasonable fit for five of the seven metrics; however, the model does consistently overestimate the fall rate and underestimate low pulse duration.

Full-Market Participation

In the full-market participation scenario (FM), the dam operator takes advantage of both the day-ahead and real-time energy markets, as well as the regulation service market. In this case, a 7-day operating horizon is used, which presumes a somewhat improved predictive capacity, in terms of a utility's ability to forecast inflows and day-ahead electricity demand.

Differences between the simulated hourly operation of a dam under the day-ahead only (left) and full-market participation (right) scenarios are shown in Fig. 5. Hourly dam operations under the full-market participation scenario reflect frequent participation in the real-time energy and regulation markets, which alters the hourly dam release schedule and translates to differences in both revenues and downstream flow regime. In general, however, both scenarios reflect similar patterns of hourly operation due to season-specific

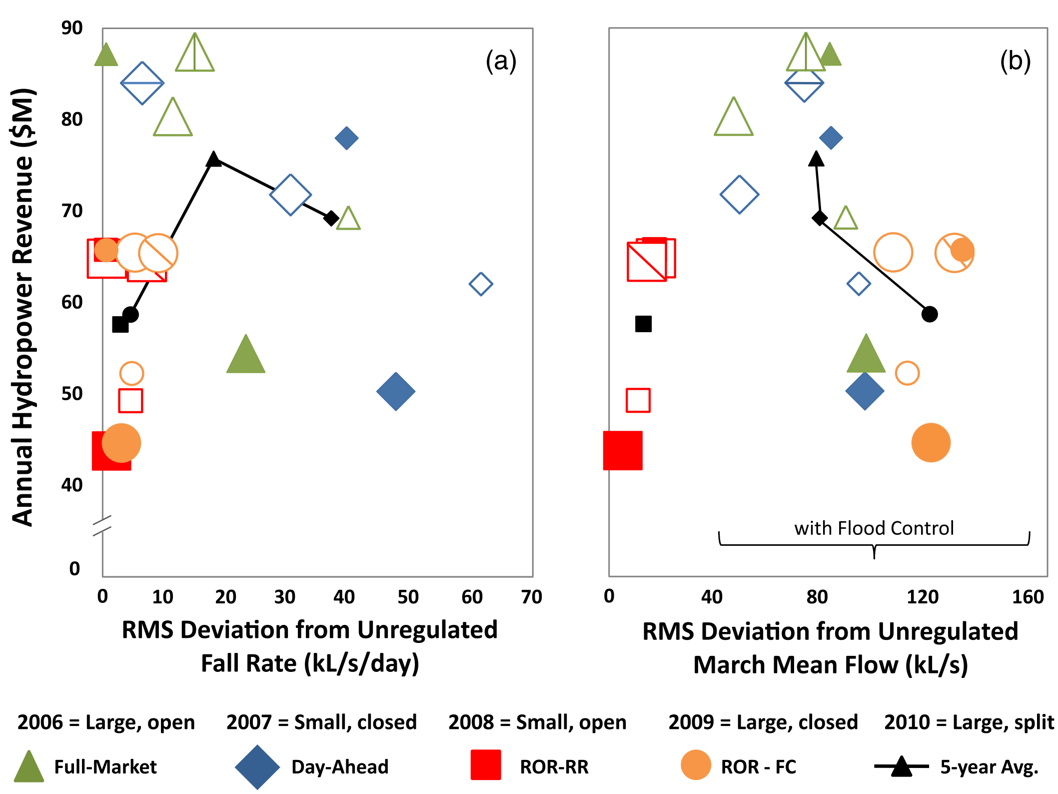

Fig. 6. Hydropower revenues versus root-mean squared deviation from (a) unregulated fall rate and (b) unregulated March mean flow; ROR = run-of-river; FC = flood control; and RR = reregulated

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variation in electricity demand, with winter days demonstrating a bimodal pattern and summer days showing one peak period.

A full-market participation scenario with flow reregulation at Roanoke Rapids Dam was also developed (FM-RR). In this case, the strict guidelines constraining lake level fluctuation at Gaston Dam are relaxed during the week. While within-week scheduling of hydropower at Kerr and Gaston Dams is performed consistent with the features of full-market participation specified above, Roanoke Rapids dam is operated without hourly peaking and in a manner that correlates daily outflow at Roanoke Rapids Dam to inflows at upstream Kerr Dam.

Run-of-River Scenarios

Two run-of-river scenarios were developed with (ROR-FC) and without (ROR) flood control capacity at Kerr Dam. A third scenario (ROR-RR) combines flow reregulation at Roanoke Rapids Dam with no flood control at Kerr Dam.

Results and Discussion

The full-market participation scenario results in the highest hydropower revenues in each year (2006–2010), followed by full-market with reregulation, the day-ahead only scenario, and then the run-of-river (ROR) scenarios (Table 2). The cumulative difference in revenue between the ROR scenarios and the day-ahead only and full-market participation scenarios is primarily a function of the ROR scenarios' guide curve storage constraints and 1-day operating horizons. These constraints, respectively, result in significantly more "spilling" (releases larger than the turbine capacity of the dams), more frequent generation during periods of relatively low electricity demand (and price), and access to fewer markets, since a 1-day operating horizon restricts participation in the real-time energy and regulation markets.

The difference in cumulative revenue between the day-ahead only and full-market participation scenarios is primarily a reflection of the differences in market participation. The day-ahead-only scenario generates US$346.1 million over five years, while the full-market participation scenario generates US$378.8 million over the same period selling energy in the day-ahead (US$306.1 million), and real-time (US$66.0 million) markets, as well as the regulation service market (US$6.7 million).

Results show that over the five year period (1) strict daily adherence to a seasonal Kerr Dam guide curve (ROR-FC) results in US$54 and $86 million less in hydropower revenues than the day-ahead and full-market scenarios, respectively; and (2) removing flood control capacity completely at Kerr Dam (ROR) increases these losses by an additional US$5 million. The reduction in revenues as a result of flow reregulation at Roanoke Rapids Dam is roughly US$8 million under ROR conditions (ROR-RR) and US $18 million under full-market participation (FM-RR).

Fig. 6 plots annual hydropower revenues against deviation from the unregulated flow regime for four operational scenarios (flow reregulation is not shown). Deviation is defined as the root-mean squared difference between regulated and unregulated flows at Roanoke Rapids Dam. Movement away from the origin along the y-axis signifies increased revenue. Along the x-axis, movement away from the origin signifies increasing divergence from unregulated flow behavior (x-value of zero would mean the regulated scenario perfectly mimics unregulated flow).

Table 3. Results for 2006–2010 (Deviation from Unregulated Flow Scenario)

		January mean flow		March mean flow		August mean flow		September mean flow		1-day max date		L. P. duration		Fall-rate	
Year	Scenario	kL/s	Deviation	kL/s	Deviation	kL/s	Deviation	kL/s	Deviation	Date	Deviation	Days	Deviation	kL/s/day	Deviation
2006	Day-Ahead	237.9	−28.2	68.7	−50.6	99.2	−6.7	89.2	17.1	12/6	161	1.68	0.17	103.5	30.9
	FM-RR	241.0	−25.2	72.2	−47.1	104.8	−1.1	85.4	13.3	12/16	171	1.57	0.06	62.2	−10.4
	Full-Market	235.3	−30.9	71.0	−48.3	107.1	1.3	82.0	9.9	12/20	175	1.65	0.14	84.1	11.6
	ROR-RR	252.4	−13.7	101.1	−18.2	86.8	−19.0	52.3	−19.8	6/28	0	1.63	0.13	71.9	−0.7
	ROR-FC	252.5	−13.7	9.2	−110.1	86.5	−19.3	51.9	−20.2	6/28	0	1.67	0.16	77.9	5.3
2007	Day-Ahead	444.6	−22.5	292.3	−86.0	98.9	17.1	164.2	−28.3	11/22	41	1.68	0.05	122.0	40.2
	FM-RR	478.2	11.1	303.7	−74.7	90.4	8.6	169.0	−23.5	11/23	40	1.52	−0.11	80.1	−1.7
	Full-Market	444.8	−22.3	292.9	−85.5	93.9	12.1	164.2	−28.3	11/22	41	1.60	−0.03	81.3	−0.6
	ROR-RR	454.1	−13.0	360.7	−17.6	67.9	−13.8	192.9	0.4	1/3	0	1.76	0.12	81.3	−0.6
	ROR-FC	454.1	−13.0	241.4	−136.9	67.8	−13.9	193.3	0.8	1/3	0	1.77	0.14	82.5	−0.6
2008	Day-Ahead	99.0	−4.7	81.1	−96.8	99.2	43.6	85.8	21.7	5/12	2	1.76	−0.04	102.0	62.3
	FM-RR	88.8	−14.9	87.5	−90.4	89.0	33.3	86.7	22.5	5/10	0	1.64	−0.15	30.5	−9.3
	Full-Market	98.6	−5.1	86.2	−91.7	93.8	38.1	84.7	20.6	5/15	5	1.69	−0.11	80.2	40.5
	ROR-RR	86.2	−17.5	166.6	−11.3	35.1	−20.5	52.0	−12.2	5/10	0	1.85	0.05	44.4	4.6
	ROR-FC	86.2	−17.5	62.3	115.6	34.5	−21.1	51.6	−12.0	5/10	0	1.82	0.02	44.6	4.8
2009	Day-Ahead	190.2	−15.8	239.8	−99.2	82.8	5.7	110.6	−43.8	6/7	2	1.60	−0.08	109.5	48.3
	FM-RR	193.3	−12.7	235.8	−103.2	96.4	19.3	93.5	−60.9	6/5	0	1.60	−0.08	49.1	−12.2
	Full-Market	187.0	−19.1	239.3	−99.7	90.6	13.4	101.9	−52.5	6/9	4	1.58	−0.10	84.9	23.6
	ROR-RR	191.7	−14.4	333.6	−5.4	66.0	−11.1	149.9	−4.4	6/5	0	1.79	0.11	62.8	1.5
	ROR-FC	191.7	−14.4	214.2	−124.8	65.9	−11.3	150.6	−3.8	6/5	0	1.67	−0.01	64.4	3.1
2010	Day-Ahead	518.0	−20.1	393.9	−75.7	97.6	13.8	88.8	23.3	12/10	27	1.75	0.02	94.2	6.5
	FM-RR	527.6	−10.5	391.6	−77.9	92.5	8.7	90.0	24.5	12/2	19	1.66	−0.08	84.7	−3.0
	Full-Market	513.6	−24.5	393.3	−76.3	98.3	14.5	86.0	20.5	2/9	87	1.67	−0.07	72.5	−15.2
	ROR-RR	530.7	−7.4	454.9	−14.7	69.0	−14.8	56.8	−8.7	11/13	0	1.80	0.07	94.9	7.3
	ROR-FC	530.7	−7.4	335.8	−133.8	69.0	−14.8	56.8	−8.7	11/13	0	1.74	0.01	96.8	9.2

Note: Statistics for ROR (not shown) are identical to ROR-RR. FM = full market; ROR = run-of-river; RR = reregulated; FC = flood control capacity.

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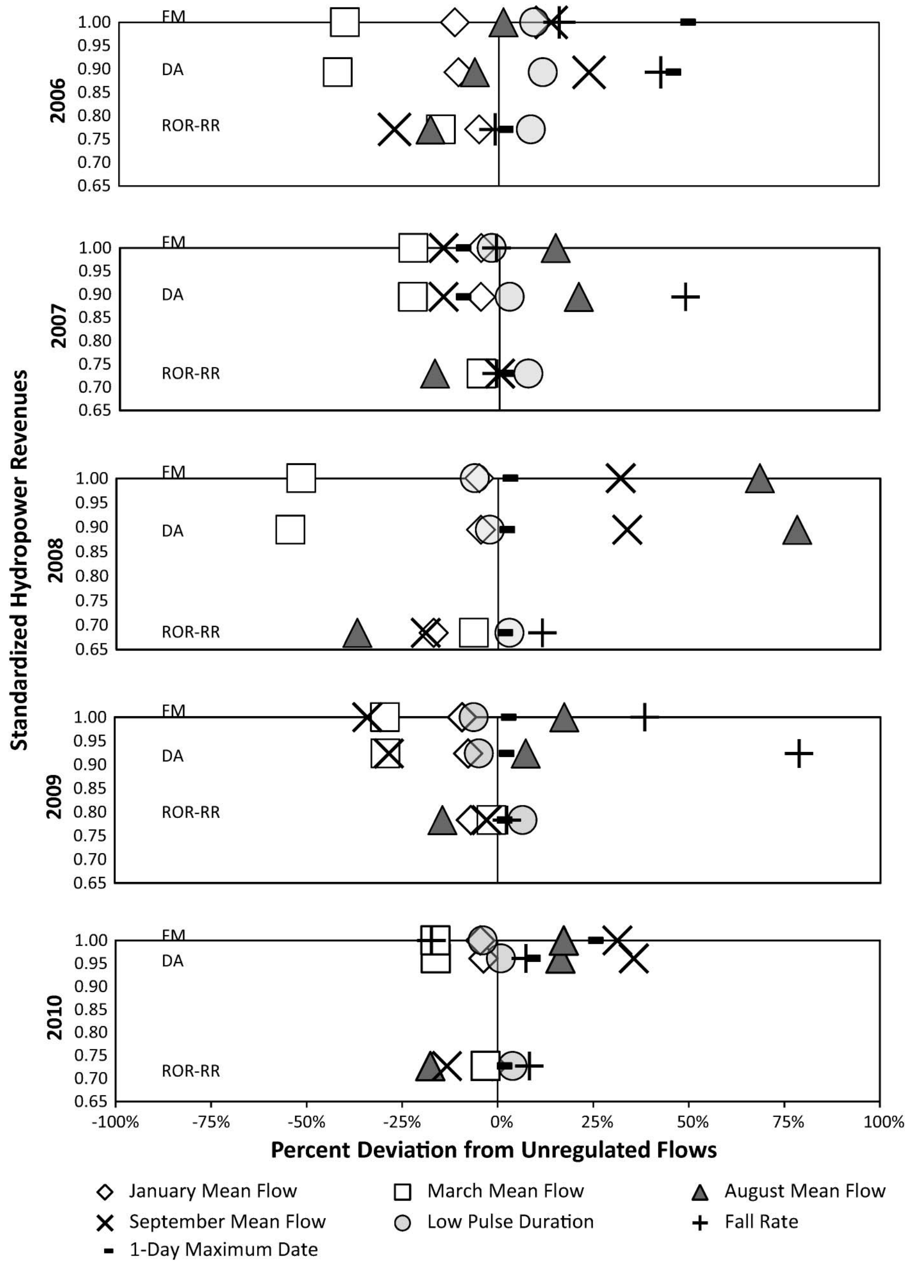

Fig. 7. Standardized hydropower revenue versus percentage deviation from unregulated flow

An overall positive relationship between hydropower revenues and deviation from unregulated flows implies a trade-off between downstream environmental quality and hydropower revenue (e.g., more revenue, lower environmental quality). This trade-off is present in the results for 1-day maximum flow date (all years), January mean flow (2006–7, 2009–10) and September mean flow (2009).

Results for most IHAs show a somewhat mixed but overall positive result, such as data for fall rate [Fig. 6(a), 2006–2009] and September mean flow (2006 and 2008), where day-ahead only leads to greater deviation than full-market participation but produces less revenue.

Other IHA metrics, such as August and September mean flows (2006) yield a negative relationship, where greater revenue coincides with more "natural" flows. March mean flow [Fig. 6(b)] presents an interesting example of a negative relationship between revenue and deviation from unregulated flows under flood control conditions; then, as flood control capacity is removed, flows revert back to a much more natural state.

Annual results for many of the IHAs considered show a high level of interannual variability. Only two IHAs (March mean flow and 1-day maximum flow date) demonstrate a consistent trend between revenue and deviation from the unregulated flows over five years.

Table 3 shows results for each regulated scenario (2006–2010), including values for each IHA (along with + /– deviation from unregulated flows) and revenue. In general, IHA values for the day-ahead only and full-market participation scenarios are relatively similar, even as the full-market scenario generates more revenue in each of the five years; larger differences are observed when the full-market and day-ahead scenarios are compared with the ROR scenarios or with the full-market reregulated scenario.

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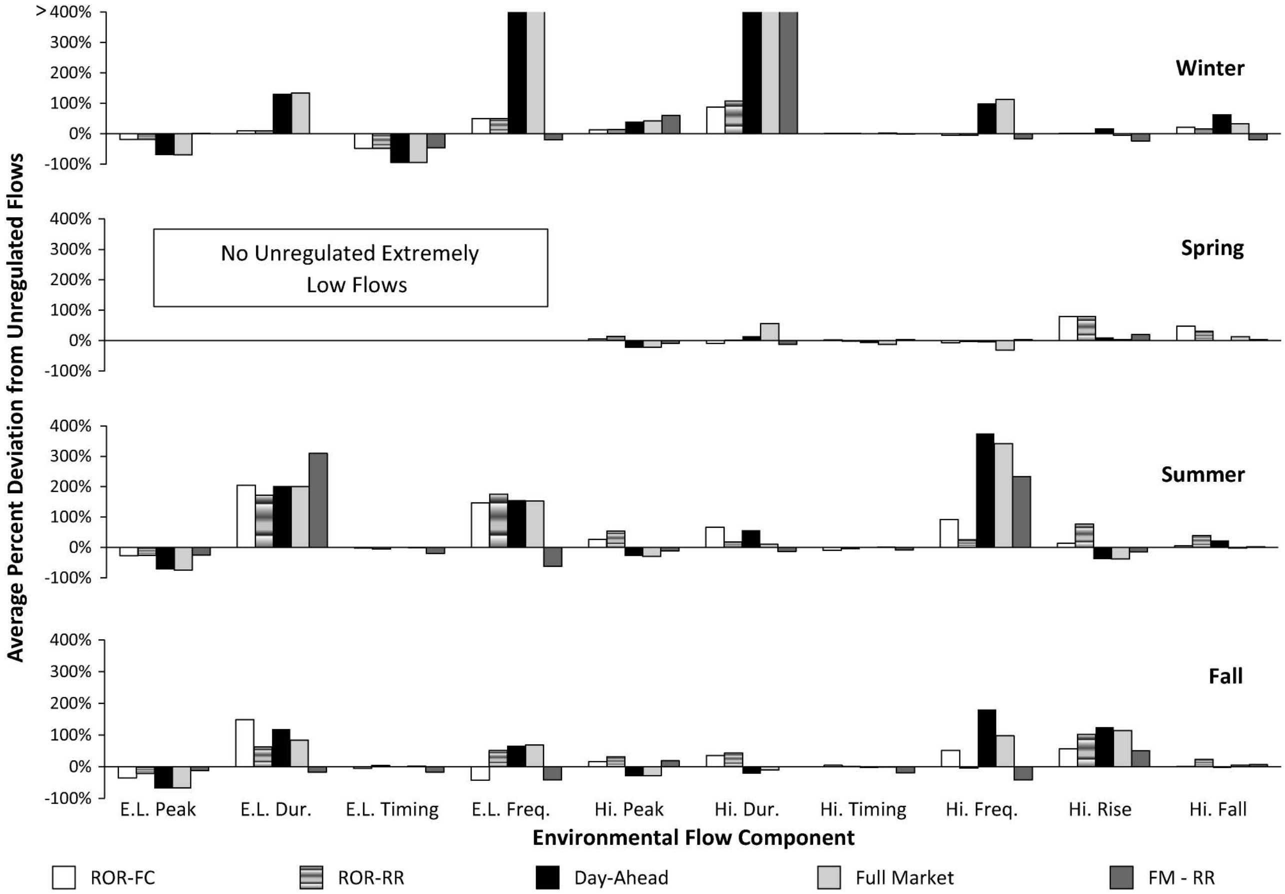

Fig. 8. Average 5-year percent deviation from unregulated flows in terms of selected environmental flow components; values for ROR (not shown) are equal to ROR-RR

Quantifying a particular scenario's aggregate impact on flow regime is complicated by the use of IHAs with various units, so calculations of the percentage deviation from unregulated flows are used to gauge the impact of each regulated scenario. These calculated values correspond to 210 data points (6 scenarios × 5 years × 7 IHAs), which were found to generally follow a normal distribution. Grubbs' test for outliers ($n = 210$; 99.7% confidence interval) was used to identify and remove two statistical outliers (2008 fall rate data for the day-ahead and full-market scenarios). Fig. 7 shows results for full-market participation (FM), day-ahead only (DA), and run-of-river reregulated (without flood control, ROR-RR) plotted according to annual revenue and percentage deviation from unregulated flows. Each plot shows standardized revenue on the *y*-axis and percentage deviation from unregulated flows on the *x*-axis. The unregulated scenario is represented by the origin (the point of \$0 and 0% deviation).

The full-market participation and day-ahead only scenarios show a high degree of similarity in terms of flow regime, as evidenced by the proximity of their respective IHA markers along the *x*-axis. Thus, changes in dam operations designed to take advantage of market deregulation appear to have a relatively small impact on flow regime. On the other hand, the difference in revenue between these two scenarios ranges from 4%–11% annually (summing to US\$32.7 million over five years).

Environmental flow components (EFCs) provide additional information regarding each scenario's impact on flow regime. Fig. 8 shows the 5-year average percent difference between each of the six regulated scenarios and unregulated flows in terms of two EFCs, extremely low (EL) flows and high-flow (Hi.) pulses. In general, results suggest that the most significant impacts to extremely low flows are in terms of their frequency and duration (both increased). During winter, the full-market (FM) and day-ahead scenarios are shown to exacerbate deviation in these two categories (while differences between the two scenarios remain minimal); but during the rest of the year, the day-ahead and full-market scenarios often perform as well or better than the ROR scenarios. The regulated scenarios all produce extremely low flows during spring, whereas the unregulated scenario results in none.

Extended duration high-flow pulses have been identified as a potential threat to downstream ecosystems in the Roanoke River basin (Pearsall 2005). Results from the EFC analysis suggest that the day-ahead and full-market scenarios demonstrate the greatest deviation from unregulated flows during winter months (increasing both the frequency and duration of high-flow pulses); during summer months, these two scenarios significantly increase the frequency (but not duration) of high-flow events relative to the other regulated scenarios.

Results are not shown for small and large floods but merit discussion. Unregulated flows over the 5-year period result in five small floods (events with peak daily flow $>= 1{,}409.3\ \mathrm{kL/s}$): three in winter, and one each in summer and spring. While each ROR scenario is successful in reproducing the magnitude, duration, frequency, timing, and rate of change of these small flood events, the full-market with flow reregulation scenario results in only one small flood over five years and all other regulated scenarios result in zero. A similar trend exists for large floods (events with peak

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daily flow $>= 2{,}542.9$ kL/s); only one large flood results from unregulated flows, but aside from the ROR scenarios, no regulated scenario reproduces this event.

Considering their objective to more closely mimic unregulated flows, the performances of the ROR scenarios are fairly successful over the period 2006–2010. There is a significant difference between the ROR and other regulated scenarios (one that indicates, for most IHAs and EFCs considered, a more natural flow regime). In many other cases the ROR scenarios more closely mimic unregulated flows, but these improvements are relatively minor, and in a few instances the ROR scenarios result in greater deviation from unregulated flows.

Conclusions

The general trend between hydropower revenue and deviation from unregulated flows over the five years considered appears to be positive (i.e., higher revenues correspond to greater deviation from the natural flow regime), albeit somewhat variable across the IHAs and EFCs used in this study, as well as dependant on the year in question. This finding primarily reflects the similar nature of flows resulting from the full-market participation and day-ahead only scenarios, as well as the ability of the ROR scenarios to somewhat reduce deviation from unregulated flows. When comparing the day-ahead only and full-market participation scenarios, the scale of the differences in flow regime between the two is relatively small, while the added revenue generating potential of the latter appears significant. Implementing a ROR policy (with or without flood control) would likely result in flow regimes that mimic unregulated flows somewhat better than the other regulated scenarios in most years but result in significantly smaller generating revenues. The differences between the ROR policies appear minor in terms of both hydropower revenue and flow regime, with a few exceptions.

Interpreting the results of this study depends on the ability of the IHAs and EFCs (Table 1) to measure hydrologic disturbance in a biologically and ecologically significant way. The use of IHAs and EFCs in previous studies has established this method as an accepted way to quantify hydrologic alteration following a disturbance (e.g., a dam or land-use change). However, because use of these metrics stipulates a maximum temporal resolution of 1-day, it is likely that IHAs and EFCs do not fully capture the potential for impacts on downstream flow regime from electricity markets. Due to the hourly variation of market prices, deregulated electricity markets such as PJM have the potential to significantly change current hydropower operations on an hourly or sub-hourly basis. Consequently, one would expect the effects of these sorts of markets on flow regime to be more evident when analyzed on an hourly time step. This highlights the need for research into the effects of flow variations at smaller time resolutions, which would facilitate further investigation of the effects of not only market dynamics, but also strategies that aim to reduce deviation from natural flows, such as hourly reregulation of flows.

Acknowledgments

The authors would like to thank the anonymous reviewers of this paper, whose criticism and suggestions for improvement were most welcome, as well as our funding sources: the North Carolina Department of Environment and Natural Resources, Progress Energy, and the Hydropower Research Foundation.

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